STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN RE: ORLANDO UTILITIES COMMISSION,
CURTIS H. STANTON ENERGY CENTER
UNIT B IGCC PROJECT
POWER PLANT SITING
SUPPLEMENTAL APPLICATION NO. PA 81-14SA3

DOAH Case No. 06-0735EP
DEP OGC NO. 06-0491

FINAL ORDER

Pursuant to §403.508(6), Florida Statues ("F.S."), the administrative law judge ("ALJ") in this cause issued an order on October 31, 2006, granting the request of the parties to cancel the certification hearing. Therefore, the Department of Environmental Protection ("DEP") is required to prepare and issue a final order in accordance with §403.509(1)(a), F.S. On November 13, 2006, DEP and the co-applicants, Orlando Utilities Commission ("OUC") and the Southern Power Company-Orlando Gasification LLC ("Southern"), submitted their Joint Proposed Recommended Order in this case. The matter is now before DEP for issuance of the final order.

PARTIES

Pursuant to §403.508(4), F.S., the parties are OUC and Southern as co-applicants (collectively, "Applicants"); DEP; the Florida Department of Community Affairs ("FDCA"); Orange County; and the Florida Department of Transportation ("FDOT"). No other person or agency filed a notice of intent to be a party or a motion to intervene under §403.508, F.S.

STATEMENT OF THE ISSUE

The issue to be decided in this proceeding is whether DEP, acting in lieu of the Siting Board, should approve certification in accordance with the Florida Electrical Power Plant Siting Act, §§403.501, *et seq.*, F.S., authorizing OUC and Southern to construct and operate a new integrated gasification combined cycle unit ("IGCC Project" or "Unit B"), providing an additional nominal 285 megawatts ("MW") of power at OUC's existing Curtis H. Stanton Energy Center in Orange County, Florida.

PRELIMINARY STATEMENT

On February 17, 2006, Applicants jointly filed a Supplemental Site Certification Application ("SSCA") to construct and operate a new electrical power plant unit (Unit B) in southeast Orange County, Florida. The project site is located approximately ten miles southeast of Orlando, approximately one mile north of the Bee Line Highway and eight miles south of State Road 50 (Colonial Drive).

The application for Unit B included a request for unit capacity determination of nominal 285 MW in total. DEP determined the SSCA to be sufficient on June 7, 2006. Several reviewing agencies have submitted reports on the IGCC Project and have proposed Conditions of Certification. On August 18, 2006, DEP issued its Staff Analysis Report ("SAR"), incorporating the reports of the reviewing agencies. The SAR recommends certification of the proposed Curtis H. Stanton Energy Center Unit B IGCC Project subject to a comprehensive set of Conditions of Certification.

No party to this proceeding is recommending denial of certification for the IGCC Project or denial of a nominal unit capacity determination of 285 MW. The parties agree that the Site Certification Application, as supplemented by the

Applicants' Sufficiency Responses filed on May 8, 2006, in reply to agency deficiency questions, and the agreed-upon Conditions of Certification, provide reasonable assurance that construction and operation of the proposed Unit B Project will comply with all applicable agency standards.

Public notice of the Filing of Supplemental Application for Electrical Power Plant Site Certification was published by the Applicants in the Orlando Sentinel on March 18, 2006, and by the Department on March 10, 2006, in the Florida Administrative Weekly ("FAW"). Pursuant to §403.5115(1)(e), F.S., notice of the certification hearing scheduled for November 27 and 28, 2006, was published by DEP on October 6, 2006, in the FAW and by the Applicants on October 13, 2006, in the Orlando Sentinel.

On October 19, 2006, the Applicants, DEP, Orange County, FDOT and FDCA filed a Joint Stipulation addressing certification issues. In the Stipulation, all parties have agreed that the IGCC Project should be certified, subject to appropriate Conditions of Certification, which have been agreed to by all parties. All parties have also agreed on the nominal unit capacity determination of 285 MW.

Pursuant to §403.508(6)(a), F.S., a certification hearing may be cancelled if, no earlier than 29 days prior to the certification hearing, DEP or the applicant requests that the ALJ cancel the certification hearing and relinquish jurisdiction to DEP. The Joint Stipulation of October 19, 2006, included such a request, and stipulated that there are no disputed issues of fact or law to be raised at the hearing. Sufficient time remained for the applicant or DEP to publish public notices of the cancellation of the hearing at least three days prior to the scheduled hearing date.

Pursuant to §403.508(6)(b), F.S., the ALJ issued an order on October 31, 2006, granting the joint request to cancel the certification hearing. DEP published notice of cancellation of the certification hearing in the FAW on November 22, 2006, and the Applicants published similar notices on November 17, 2006.

FINDINGS OF FACT

Background

1. The Curtis H. Stanton Energy Center site was initially certified by the Siting Board on December 15, 1982, for an ultimate site capacity of 2,000 MW. On that date, the Siting Board also approved the coal-fired Unit 1 with a nominal capacity of 465 MW. On December 17, 1991, the Siting Board certified OUC's supplemental application for Stanton Unit 2, another coal-fired unit. On September 11, 2001, the Siting Board certified a supplemental application filed by OUC along with Kissimmee Utility Authority, the Florida Municipal Power Authority and Southern-Florida, LLC for a natural gas-fired Combined Cycle Unit A at the Stanton Energy Center site (SAR at 2).

PSC Need Determination

2. On May 24, 2006, the Florida Public Service Commission ("PSC") issued an Order Granting OUC's Determination of Need for the Stanton 3 IGCC electrical power plant unit (Order No. 06-0457-FOF-EM, PSC). In its Order, issued pursuant to §403.519, F.S., the PSC determined there is a need for the Project, taking into account electric system reliability and integrity (SAR, Appendix II-1). The PSC determined that OUC needs the Stanton B IGCC Project to satisfy forecast capacity requirements to maintain its 15 percent reserve margin criteria beginning in the

summer of 2010. The PSC further determined that the Project is the best, most cost-effective alternative available (*id.*)

<u>The Existing OUC Power Plant Site</u>

3. The OUC Curtis H. Stanton Energy Center certified site encompasses 3,280 acres. Approximately 1,100 acres of this is occupied by the power block and associated facilities (SAR at 2, 22).

4. Approximately 35 acres of the site will be developed for Unit B's permanent power generation facilities (*id.* at 22). Ninety-three acres are currently used for the existing cooling water supply pond, which will also supply Unit B. (*id.* at 2, 22). These are wholly within OUC's existing 3,280-acre Curtis H. Stanton Energy Center site and they also lie within the 1,100 acres which have already been scheduled for use for power development. Most of the remaining 2,180 acres of the site has been left in its preexisting natural condition and provides buffer between the main generating units and the surrounding area. Approximately 2,000 acres are set aside for red-cockaded woodpecker habitat and buffer areas (*id.* at 22). The Curtis H. Stanton Energy Center now includes Units 1 and 2, two coal-fired generating units producing a nominal, net 886 MW of electric power as well as Unit A, a combined cycle gas-fired unit producing a nominal, net 633 MW of electric power. Therefore, the site generating capacity is currently at a nominal 1519 MW (*id.* at 2).

5. Existing facilities on the Stanton site include the two coal-fired units and associated natural draft cooling towers, and Unit A, a two-on-one combined cycle gas-fired unit consisting of one combustion turbine with heat recovery steam generation, one steam electric generating turbine, a six-cell wet evaporative

mechanical draft cooling tower, a coal pile, a natural gas pipeline and ancillary equipment including process water treatment (*id.*)

The Proposed Unit B, IGCC Project Area

6. The construction phase of the proposed Unit B IGCC Project will involve most portions of the Stanton site already developed (i.e., within the 1,100 acre developed area) for energy production. In general, the project will take advantage of the existing overall infrastructure (e.g., plant roads and onsite electrical substation) provided by the Stanton Site (*id.* at 22). The project will benefit from the existing coal delivery and handling facilities; the existing potable water, cooling water and wastewater systems; and the existing solid waste landfill (SSCA, Vol. I at 2-2).

Land Use Compatibility

7. The entire Curtis H. Stanton Energy Center site is zoned Farmland Rural. A 1981 resolution by the Orange County Board of County Commissioners granted a special exception permitting the construction of the Curtis H. Stanton Energy Center and associated facilities within the A-2 zoning district. The special exception was applied to the entire 3,280 acre site, including its application to future units such as Unit B (*id.* at 2-15).

8. Land use/zoning consistency and compliance with the Orange County Local Comprehensive Plan has already been determined for Unit B. No expansion to the boundaries of the certified site is proposed (*id.*) Because the previous certified ultimate site capacity is not exceeded and the lands required for the construction and operation of the power plant are within the boundaries of the previously certified site,

a new land use determination is not applicable to the instant proceeding [§§403.517(2), F.S.]

Hydrogeology

9. There are three aquifers beneath the proposed site for Unit B: the unconfined, intermediate secondary artesian, and Floridan aquifers. At the site, the bottom of the unconfined aquifer was encountered at depths ranging from 32 to 71 feet below ground surface (bgs), the top of the intermediate cohesive layer. Beneath the intermediate cohesive layer, there are approximately 80 feet of sand underlain by the lower cohesive layer (*id.* at 2-55).

10. The intermediate secondary artesian aquifer under the site has a thickness ranging from 125 to 156 feet, which includes the intermediate cohesive layer, lower sand layer, and lower cohesive layer. Due to the absence of the intermediate cohesive layer at some boring locations, the continuous lower cohesive layer is believed to act as the primary aquitard between the unconfined and Floridan aquifers underneath the site. The lower cohesive layer has a thickness of approximately 50 feet (*id.*)

11. The Stanton site is located in an area where the potentiometric surface is near the land surface and the clastic overburden is greater than 100 feet thick. A sinkhole evaluation study performed during the original site evaluation for certification of the entire Stanton site concluded that the potential for sinkholes is very low. No sinkholes have been reported at the site since the original site evaluation, and sinkholes are not expected to occur at the site in the future (*id.*)

Ecological Impacts

12. The Stanton Energy Center was studied rigorously for ecological resources in preparation for filing the SCA for overall site certification and for Unit 1. For the permitting of Stanton Unit A in 2001 and supplemental amendments, additional ecological studies were performed. Results of those studies appear in the Unit A Supplemental SCA, the environmental resource permit (ERP) application for Unit A, and the ongoing ecological monitoring reports for the entire property. The ongoing ecological studies at Stanton are primarily associated with the required monitoring of the endangered red cockaded woodpecker populations onsite (*id.* at 2-74).

13. The predominant upland vegetation cover type is pine flatwoods, an upland, fire climax community with flat to slightly sloping topography and well to moderately well drained soils. The pine flatwoods onsite are being burned at periodic intervals to maintain their natural state. Saw palmetto (*Seronoa repens*) is the most abundant shrub in the flatwoods. 0ther common Florida shrub species are found within the pine flatwoods. Other upland vegetation cover types include improved pasture, herbaceous upland non-forested, shrub and brushland, and mixed upland non-forested area (*id.* at 2-77, 78). No wetlands appear within the developed portion of the Stanton site upon which Unit B will be constructed (*id.* at 2-82). A short transmission line within the Stanton site will connect Unit B with an existing substation and will impact approximately four acres of wetlands [Applicants' Sufficiency Responses, May 8, 2006 ("Sufficiency Responses"), Attachment

CENTRAL FDEP-C.1 (Joint Application for Environmental Resource Permit, "Joint Application") at 16].

14. Common wildlife species found in central Florida occur over the entire acreage and diverse habitats of the Stanton site. However, the total acreage encompassed by the Unit B Project footprint contains power plant facilities, managed landscapes, and ruderal communities. Wildlife usage is therefore expected to be lower than in natural habitats occurring over the remainder of the Stanton site outside of the power production area (SSCA at 2-94).

Archeological and Historic Sites

15. In March 1981, the Florida Department of State, Division of Archives, History, and Records Management determined that the existing site did not represent significant archaeological or historical resources. Construction of Stanton Unit B is unlikely to affect any properties listed, or eligible for listing, in the National Register (*id.* at 2-26).

Socioeconomic Impacts

16. Construction of Stanton Unit B will have a significant positive impact on the local economy, providing approximately 700 construction jobs at the peak of construction during the 28-month construction period. The vast majority of the construction work force is expected to consist of workers already residing in the study area (Brevard, Osceola, Orange, Lake, and Seminole Counties) (*id.*) The estimated annual construction payroll is $64 million (in 2006 dollars). In addition, 53 permanent jobs and an annual payroll of $6 million are expected from the construction of Unit B (*id.* at 4-11; 7-3).

Scheduling

17. Mobilization and physical construction of Stanton Unit B are scheduled to begin in the fourth quarter of 2007, with commercial operation scheduled to commence June 1, 2010 (*id.* at 1-1).

Stanton Unit B Project Design: Integrated Gasification Combined Cycle (IGCC)

18. Powder River Basin ("PRB") coal is the feedstock to used produce synthetic gas ("syngas") (*id.* at 7-9).

19. The purpose of the Unit B design is to integrate a transport gasifier with a new combined-cycle unit (*id.* at 3-4 and 5). Unit B will be a 1x1 F-class IGCC unit with a nominal rating of 285 MW on syngas and 229 MW when burning natural gas. Unit B will consist of one combustion turbine with heat recovery steam generation, one steam electric generating turbine, a multi-cell mechanical draft cooling tower, a gasification island with flare, a coal pile, a natural gas pipeline and ancillary equipment including process water treatment. Natural gas may be used as an alternative fuel (SAR at 2).

20. The primary combustion turbine unit to be installed is a General Electric "F" Class (PG7241 FA) combustion turbine-electrical generator, fired with pipeline natural gas or syngas and equipped with evaporative coolers on the inlet air system. The project includes one heat recovery steam generator (HRSG) with a 205 foot high stack and one steam turbine electrical generator. Duct burners will be installed in the WRSG for supplemental firing (natural gas only) to achieve peak output (*id.*)

21. A multi-cell, mechanical draft, counter flow cooling tower will be used for plant cooling. The cooling tower will be of fiberglass construction and will be installed

on a reinforced concrete basin, which will include a pump intake structure housing two 50 percent capacity circulating water pumps and two 100 percent capacity auxiliary circulating water pumps (*id.*)

22. The auxiliary closed loop cooling water system will include three 50 percent capacity plate and frame heat exchangers. A circulating water chemical feed system will also be included. The cooling tower will be equipped with drift eliminators (*id.*)

Construction of Unit B Facilities

23. Stanton Unit B will not require the use of explosives for any portion of the construction work (SSCA, Vol. I at 4-3).

24. Laydown areas for storage of construction materials and plant equipment components will be required for the construction of Unit B. Approximately 20 acres of land will be needed for storage and staging of materials and equipment. The laydown area will be graded for proper drainage, and a course of gravel-based material will be applied if necessary. Wood timbers will be used, as appropriate, to help keep plant equipment components and materials stored safely off the ground. After construction is complete and laydown areas are no longer needed, wood timbers will be removed and the surface areas will be graded for drainage and planted with grass (*id.*)

Construction Impacts

25. The existing terrain is essentially flat. The contours of site terrain will not be altered to any significant degree by Unit B construction activities (*id.* at 4-5).

26. Access for the construction activities will be provided by the existing access road and site entrance. No new roads are proposed for construction as a result of this project (*id.*)

27. An erosion control plan will be implemented to minimize impacts on surface water bodies during construction (*id.* at 4-6).

28. The potential effects on existing water quality of the surficial aquifer due to earth-moving and dewatering activities during site preparation and construction are anticipated to be minimal and temporary. This is due to low groundwater flow velocities in the area and the fact that any surficial aquifer drawdown impacts will be localized on less than 25 acres within the Stanton Energy Center site boundaries (*id.* at 4-6 and 7).

29. No forested areas of natural communities will be affected by construction of the Unit B power block or placement of the coal pile. The entire footprint of the Unit B facility will occur on previously altered habitats. While these land cover types will remain within the current Florida Land Use Cover and Forms Classification System (FLUCFCS) designations after construction of Unit B, some remnant ruderal habitats will be permanently displaced. The displaced habitats include approximately 35 acres used for the power block and coal handling facilities. These areas are managed lawnscapes. Gradually, additional solid waste disposal areas will be prepared for operation of Unit B, also displacing ruderal communities (*id.* at 4-9). A short transmission line within the Stanton site will connect Unit B with an existing substation and will impact approximately four acres of wetlands (Joint Application at 16).

30. Although wildlife usage of these habitats is limited, the project will result in a net decrease of these ruderal areas. This will cause relocation of these wildlife species to other similar habitats on the Stanton property. Construction of the Unit B power block and coal pile is not expected to affect any important habitats for state or federally listed plants or wildlife. Regional populations of wildlife or listed species will not be affected by construction of Unit B. Unit B construction may, however, temporarily displace some wildlife species in the immediate project vicinity due to increased noise, dust and human presence (SSCA, Vol. I at 4-9 and 10).

Surface Water Impacts and Stormwater Management

31. The Unit B Project does not propose surface water diversions, interceptions, additions to surface water flow, or withdrawals or consumptive use of surface waters. Unit B's use of groundwater will be carefully limited to ensure that draw down does not affect surface waters. Accordingly, Unit B construction and operation will not affect surface water quantities or qualities, or affect the natural hydrological process of the areas on or surrounding the site (*id.* at 5-4; 5-5).

32. Stormwater from the Unit B construction area will ultimately flow into the existing Stanton stormwater management system and will be contained within the developed, previously impacted power production portion of the site. Stormwater runoff from the coal storage pile associated with Unit B, and from the landfill where gasification ash and sulfur will be stored, will be handled as it is for existing Stanton facilities (*id.*) Following construction, the stormwater management plan will take advantage of existing systems and will protect adjacent water bodies from the stormwater runoff associated with Unit B (*id.* at 5-6). In addition, while constructing

the individual transmission line tower pads, the construction crew will utilize Best Management Practices ("BMPs") (e.g., silt screens, hay bales, etc.) to minimize runoff. Thus no additional significant impacts are expected from the management of stormwater from the Unit B construction area (*id.* at 4-7).

Solid and Hazardous Waste Disposal

33. The principal by-product that will be produced by the operation of Unit B is gasification ash [approximately 68,000 tons per year (TPY)] (SAR at 4.) Elemental sulfur will also be generated by the gasification process, but in substantially lesser quantities (approximately 2,800 TPY). The original Stanton Conditions of Certification do allow for the disposal of ash in the on-site landfill. Thus, both the ash and the elemental sulfur may be land-filled into the existing, permitted Stanton landfill, although markets for other, beneficial uses will be sought for each byproduct (*id.*) Prior to disposing of new gasification ash in the landfill, the existing waste management plan will be amended to include gasification ash disposal (Sufficiency Responses at 53).

34. Gasification ash will be subjected to a controlled test, analyzing for constituents of concern to DEP (*id.*) The Applicants will work with DEP to identify an appropriate monitoring plan based on the results of this test (Sufficiency Responses at 47). Any hazardous wastes generated during operation, potentially including spent sorbents, will be properly manifested and disposed of according to state regulations. As the quantities and types of hazardous wastes are expected to be ordinary and of low volume, no significant impacts are expected to result to any existing regional hazardous waste disposal facilities (SAR at 5).

Water Use and Sources

35. Unit B will obtain all necessary water for operations from existing Stanton systems or sources. The principal sources of water used at Stanton are reclaimed water (treated effluent) from the County's nearby Eastern Water Reclamation Facility, a county-owned wastewater treatment plant in proximity to the site, and groundwater from onsite wells. The addition of the new Unit B at Stanton will require a greater supply of reclaimed water. On an annual average basis, approximately 2.6 MGD of reclaimed water will be drawn from the onsite storage pond. On a short-term basis, water use can change due to changes in ambient temperatures and/or relative humidity, both of which affect consumption of water. Other variables that impact water use are plant load and cooling tower cycles of concentration (SSCA, Vol. I at 3-47).

36. The cooling water system at Stanton Unit B will create the largest demand for water. One of Stanton Energy Center's prominent features is the use of treated effluent to supply makeup water to the cooling systems, thereby recycling this water and displacing the need for higher quality water. More than 80 percent of the cooling system demand is related to the combined-cycle unit's operation, while less than 20 percent is attributable to the gasification processes. Makeup water must be supplied to this system to replace cooling tower evaporative losses and blowdown, water discharged from the system to maintain water quality in the cooling tower at levels necessary for the system's proper functioning. Non-cooling water requirements will include makeup to the HRSG, makeup to the CT evaporative cooler, and potable water (*id.* at 3-48).

37. The source of makeup water for the new cooling tower will be the reclaimed water supplied to OUC at the site boundary from Orange County's Eastern Water Reclamation Facility (*id.* at 3-47, 48). A maximum of 2.6 million gallons per day (mgd) of makeup water is expected to be required for Stanton Unit B (*id.* at 3-55 and 5-5).

38. Unit B will use groundwater for processes requiring higher quality water. Demineralized makeup water and potable water will be supplied from existing OUC systems which utilize groundwater from onsite wells tapping the Upper Floridan aquifer. The total groundwater withdrawals for all uses on the Stanton site will remain within previous limits established in the existing Conditions of Certification for the Curtis H. Stanton Energy Center (SAR at 4).

39. Currently, groundwater withdrawals to support the three existing units average 0.5 mgd. Another .2 mgd will be needed to support new Unit B. The currently permitted maximum daily level of groundwater withdrawal (2.0 mgd) was evaluated in the application for Unit A and found to result in acceptable levels of impact to the aquifer. No changes to the permitted limits will be required for the Unit B project (*id.*)

40. The noise levels at and near the Stanton site are a product of operation of the power plant, other human activity, and natural sources. Noise attributable to construction activities is highly variable, depending upon the location and operation load of the construction equipment. Noise during site clearing and will be dominated by diesel engine noise. Site clearing and facility start-up will generally result in minimal noise. A onetime significant source of noise associated with facility start-up will be steam blowout of the HRSG and steam lines and of the gasifier lines.

Construction activities will be scheduled during daytime and evening periods (7:00 a.m. to 10:00 p.m.) to the fullest extent possible. Any nighttime construction will be limited to low noise activities as much as possible (SSCA, Vol. I at 4-15).

41. Noise levels are regulated under Chapter 15, Article V, of the Orange County Code (*id.* at 2-131). Background noise level was measured at several locations on the Stanton site and in the immediate vicinity, with measured noise levels in the area of the Stanton Energy Center that may be characterized as typical of an urban area (*id.* at 2-132 to 2-135). The predicted A-weighted noise emissions will satisfy the code criteria at the nearest residential locations (*id.* at 2-131).

Impacts from Flooding and Hurricanes

42. The 100 year flood elevations on the Stanton Energy Center property vary from approximately 60 feet mean sea level ("MSL") at the northeast corner of the property to approximately 90 feet MSL at the southwest corner. All Stanton Unit B facilities will be located above the 100 year flood elevation. No construction of any facilities associated with the Project will occur within any area designated as a flood zone (*id.* at 2-8). Thus no impacts on the 100 year flood plain upstream, downstream or at the site will result from the Unit B Project (Sufficiency Responses at 42.)

Public Services

43. Public services including police, fire, and emergency medical services are available and sufficient to meet the needs of Stanton Energy Center (SSCA, Vol. I at 2-30).

On-Site Transmission Line

44. Stanton has an existing, onsite 230-kV electrical substation. Only a short, onsite transmission line will be needed to connect Unit B to the electrical grid. No new offsite associated transmission facilities need to be constructed. The close proximity of Unit B to this existing substation will minimize the potential for energy losses, expenses, and environmental impacts associated with the project's interconnection to the State's transmission grid (SAR at 13).

Variances

45. No variances will be required for operation of the Stanton Unit B and its associated facilities (SSCA, Vol. I at 4-23).

Traffic

46. FDOT reviewed the impacts of Unit B on area highways, including Alafaya Trail and Avalon Park Boulevard and submitted its Conditions of Certification, including a recommended Construction Impact Mitigation Program for the Applicants to develop and implement in consultation with FDOT (SAR, Appendix I at 104). Because a majority of the heavy construction vehicles are expected to remain on site for the duration of the initial construction and thus will not make daily trips to and from the site, the potential traffic impacts from these vehicles are expected to be minimal on the regional road network (SSCA, Vol. I at 5-27). The completion of Innovation Way, expected in 2008, will also greatly improve traffic flow and reduce the impacts of Unit B construction traffic on area roadways (*id.* at 4-19 to 4-21).

Air Emissions and Air Quality Impact Analysis

47. Air emissions from the Stanton B IGCC Unit are expected to cause only minimal or insignificant impacts on vegetation, wildlife or soils (SAR at 33).

48. A regional haze analysis showed that operation of the Stanton B IGCC Unit will not result in adverse impacts on visibility in the vicinity (*id.*)

49. The Department of Environmental Protection Division of Air Resource Management ("DARM") conducted a review of an application for a Prevention of Significant Deterioration ("PSD") permit (*id.* at 3).

50. The Stanton Energy center is located in Orange County, an area designated as an attainment area for all criteria pollutants (Rule 62-204.340, F.A.C.; SSCA, Vol. II at 6-1).

51. The Unit B Project is subject to pre-construction review requirements under the provisions of Rule 62-212.400, F.A.C.

52. A preconstruction monitoring analysis is done for those pollutants with listed *de minimis* impact levels. DARM determined that the maximum predicted impacts for all pollutants with listed *de minimis* impact levels were less than the *de minimis* level. Therefore, DARM determined that no preconstruction monitoring is required for those pollutants (SAR at 29).

53. DARM determined that the emissions of NO_x in the Unit B Project as ultimately proposed will be sufficiently offset by reductions in NO_x emissions at the existing Stanton generating units, so as to obviate any requirement to perform a PSD Review for NO_x under Rule 62-212.400, F.A.C. (*id.* at 20). However, DARM determined that the Stanton Unit B is subject to PSD review, because the potential emission increase for particulate matter/particulate matter less than 10 microns

(PM/PM_{10}), carbon monoxide ("CO"),volatile organic compounds ("VOC"), sulfur dioxides (SO_2), and sulfuric acid mist ("SAM") exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C. (*id.* at 24). The PSD review consisted of a determination of Best Available Control Technology ("BACT") for PM/PM_{10}, CO, VOC, SO_2, and SAM; an air quality impact analysis; and an assessment of the impact of Unit B on general commercial and residential growth, soils, vegetation, and visibility pursuant to Rule 62-212.400 F.A.C. (*id.* at 27-28, 32-33).

54. DARM's analysis (undertaken in accordance with computer modeling procedures approved in advance with the Department) indicated that the Stanton Unit B Project resulted in no Significant Impact Levels ("SILs") in the area surrounding the proposed facility. Therefore, DARM determined that further air quality impact studies, which would include ambient air quality standards (AAQS) and PSD increment analyses for these pollutants, were not required (*id.* at 27-28).

<u>Best Available Control Technology</u>

55. BACT is a pollutant-specific emission limit that provides the maximum degree of emission reduction, after taking into account the energy, environmental, economic impacts and other costs [Rule 62-210.100(39) F.A.C.]

56. In its analysis of the Project, DARM determined the emission limits that represent BACT (SAR, Appendix I, Attachment A at 12-14).

57. DARM determined preliminarily that the Unit B project will comply with all applicable state and federal air pollution regulations, provided that the BACT determination is implemented (*id.* At 39)

Agency Positions

58. On August 18, 2006, DEP filed its Written Analysis of the site certification application with the following recommendation: "If OUC and Southern Power Company-Orlando Gasification LLC agree to abide by the conditions of certification, attached and incorporated herein as Appendix I, the Department of Environmental Protection would recommend certification of the Curtis H. Stanton Energy Center Combined Cycle Unit I3 for the 285 MW to be generated primarily by syngas." (*Id.*)

59. The Public Service Commission found the project to be needed (*id.* at 39 and Appendix II-1).

60. The Fish and Wildlife Conservation Commission found that Unit B would have no significant impacts to fish and wildlife resources under its jurisdiction. (*id.* at 39 and Appendix II-2)

61. The St Johns River Water Management District recommended approval of the Project subject to compliance with the District's recommended conditions of certification (*id.* at 39 and Appendix II-3).

62. On May 18, 2006, FDOT submitted its report stating: "The Florida Department of Transportation recommends the certification of the proposed power plant expansion. This recommendation is made contingent upon the conditions of Section VI being addressed/met." (*Id.* at Appendix II-4).

63. The DCA did not issue an agency report on the Curtis H. Stanton Energy Center Unit B Project. However, the East Central Florida Regional Planning Council submitted a report on June 12, 2006, finding no issues pertaining to its Strategic Regional Policy Plan (id. at Appendix II-5).

64. The Orange County Board of County Commissioners ratified its Agency Report for Stanton Energy Center, Unit B on June 13, 2006 (*id.* at Appendix II-6).

65. These findings of fact are not intended to conflict with the facts and statements contained in the Conditions of Certification, and any conflict between them should be resolved in favor of the Conditions of Certification to the maximum extent possible.

CONCLUSIONS OF LAW

66. Pursuant to §403.508(6), F.S., the ALJ issued an order granting the joint request by Applicants and DEP to cancel the certification hearing within five days after receipt of the request. DEP and the Applicants published notices that the certification hearing was cancelled, in accordance with §403.5115, F.S. Furthermore, because the ALJ granted the request, DEP must prepare and issue a final order in accordance with §403.509(1)(a), F.S. Therefore, DEP has jurisdiction over the parties to and the subject matter of this proceeding.

67. In accordance with Chapters 120 and 403, F.S. and Chapter 62-17, F.A.C., proper notice was accorded to all persons, entities, and parties entitled to such notice, and appropriate notice was provided to the general public by both DEP and the Applicants. All necessary and required governmental agencies participated, and the general public had an opportunity to fully participate in the certification process. Reports or studies were issued by DEP, the Florida Fish and Wildlife Conservation Commission, the St. Johns River Water Management District, FDOT, and the East Central Florida Regional Planning Council in accordance with their various statutory duties under the PPSA.

68. The PSC has issued its affirmative determination that a need exists for the electrical generating facility and the electricity it will produce, in accordance with §402.519, F.S.

69. There is reasonable assurance that construction and operation of the Project will comply with all applicable standards of jurisdictional agencies, and that no variances or other relief from non-procedural agency standards are requested or necessary for the construction and operation of Unit B.

70. The evidence in the record reveals that the Applicants have met their burden of proof to demonstrate that Unit B meets the criteria for certification under the PPSA. The evidence shows that the location, construction, and operation of the electrical power plant and directly associated facilities will (a) provide reasonable assurance that operational safeguards are technically sufficient for the public welfare and protection; (b) comply with applicable nonprocedural requirements of agencies; (c) be consistent with applicable local government comprehensive plans and land development regulations; (d) meet the electrical energy needs of the state in an orderly and timely fashion; (e) effect a reasonable balance between the need for the facility as established pursuant to §403.519, F.S. and the impacts upon air and water quality, fish and wildlife, water resources, and other natural resources of the state resulting from the construction and operation of the facility; (f) minimize, through the use of reasonable and available methods, the adverse effects on human health, the environment, and the ecology of the land and its wildlife and the ecology of state waters and their aquatic life; and (g) serve and protect the broad interests of the public.

71. If operated and maintained in accordance with this Final Order and the Conditions of Certification contained in the SAR, the certification of the Project will fully balance the increasing demand for the siting, operation and output of electrical power plants in the State with the broad interests of the public that are protected by the PPSA.

CONCLUSION

Having reviewed the matters of record and being otherwise duly advised, DEP concludes that, if constructed and operated in accordance with the evidence presented in the record and the Conditions of Certification, the project will serve and protect the broad interest of the public and should be approved.

THEREFORE IT IS ORDERED:

Site certification of Orlando Utilities Commission and Southern Power Company - Orlando Gasification LLC, Unit B, as described in the Site Certification Application and the record as a whole, is hereby APPROVED. The Project is subject to the Supplemental Conditions of Certification, modified August 17, 2006 (SAR, Appendix I) which is attached (Exhibit A) and incorporated by reference herein.

NOTICE OF RIGHTS

Any party adversely affected by this Final Order has the right to seek judicial review of it under §120.68, F.S. Judicial review must be sought by filing a notice of appeal under Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 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 30 days after this Final Order is filed with the Clerk of the Department.

DONE AND ORDERED this 8th day of December, 2006, in Tallahassee, Leon County, Florida.

FLORIDA DEPARATMENT OF
ENVIRONMENTAL PROTECTION

Colleen M. Castille

COLLEEN M. CASTILLE, Secretary

3900 Commonwealth Blvd.
Tallahassee, FL 32399-3000

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

Kay Buchanan

CLERK

12/8/06

DATE

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been sent by U.S. mail to the following listed persons this 11th day of December, 2006:

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Fish and Wildlife Conservation Commission
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Tallahassee, FZ 32399-1L6OO

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STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

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ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER UNITS 1 & 2,
COMBINED CYCLE UNIT A AND IGCC UNIT B
PA 81-14/SA3
SUPPLEMENTAL CONDITIONS OF CERTIFICATION

Modified 08/17/06

Table of Contents

Note: Changes to the existing Conditions of Certification are identified as either <u>additions</u> or ~~deletions~~.

I. CERTIFICATION CONTROL

A. Pursuant to s. 403.501-518, F.S., the Florida Electrical Power Plant Siting Act, this certification is issued to Orlando Utilities Commission, Florida Municipal Power Agency, Kissimmee Utility Authority and Southern-Florida, LLC as joint owner/operators of Curtis H. Stanton Energy Center. Under the control of these Conditions of Certification the OUC will operate a 930 MW (nominal) facility consisting of two coal-fired Units No. 1 and No. 2, and ancillary equipment. Southern-Florida LLC will construct and operate a 633 MW gas-fired combined cycle facility known as Combined Cycle Unit A. <u>Southern Power Company – Orlando Gasification LLC will construct and operate a 285 MW syngas-fired Integrated Gasification Combined Cycle unit known as IGCC Unit B.</u> These units are located on a 3280-acre site which is located at Township 23S, Ranges 31E and 32E, Orange County, Florida. UTM coordinates are: Zone 17; 483.61 km East; 3151.1 km North.

B. The general and specific conditions contained in these Conditions of Certification, unless specifically amended or modified, are binding upon the licensees and shall apply to the construction and operation of the certified facility. If a conflict should occur between the design criteria of this project and the Conditions of Certification, the Conditions shall prevail unless amended or modified.

II. APPLICABLE RULES

The construction and operation of the certified facility shall be in accordance with all applicable provisions of Florida Statutes and Department and Water Management District rules, including the following regulations: [St. Johns River WMD: 40 C-2, 40C-3, 40C-8, 40-C21] [South Florida WMD: 40E-1, 40E-4, 40E-40, 40E-41,] 62-4, 62-17, 62-256, 62-296, 62-297, 62-301, 62-302, 62-531, 62-532, 62-550, 62-555, 62-560, 62-600, 62-601, 62-604, 62-610, 62-620, 62-621, 62-650, 62-699, 62-660, 62-701, 62-762, 62-767, 62-769, and 62-770, Florida Administrative Code (F.A.C.), or their successors as they are renumbered.

III. DEFINITIONS

The meaning of terms used herein shall be governed by the definitions contained in Chapter 403, Florida Statutes, and any regulation adopted pursuant thereto. In the event of any dispute over the meaning of a term used in these general or special conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative by the use of the commonly accepted meaning as determined by the Department. As used herein:

A. "Application" shall mean the Site Certification Application (SCA) for the certified facility, as supplemented.

B. "DEP" or Department shall mean the Florida Department of Environmental Protection.

C. "DHR" shall mean the Florida Department of State, Division of Historical Resources.

D. "Emergency conditions" shall mean urgent circumstances involving potential adverse consequences to human life or property as a result of weather conditions or other calamity, and necessitating new or replacement gas pipeline, transmission lines, or access facilities.

E. "Facility" shall mean the certified electrical power generation facility and all associated structures, including but not limited to: combustion turbine generators, heat recovery steam generators, duct burners, fossil steam boilers, steam turbine generators, selective catalytic reduction units, transformers, associated transmission lines, substations, fuel and water storage tanks, natural gas delivery metering station, air and water pollution control equipment, storm water control ponds and facilities, cooling towers, and related structures.

F. "Feasible" or "practicable" shall mean reasonably achievable considering a balance of land use impacts, environmental impacts, engineering constraints, and costs.

G. "FFWCC" shall mean the Florida Fish and Wildlife Conservation Commission.

H. "Licensee" means an applicant that has obtained a certification order for the subject project.

I. "NPDES permit" shall mean the federal National Pollutant Discharge Permit System permit issued in accordance with the federal Clean Water Act.

J. "Power plant" shall mean the electric power generating plant and associated structures to be modified or constructed on the certified site, as generally depicted in the Application.

K. "Project" shall mean the electrical power generating facility and all associated facilities.

L. "PSD permit" shall mean the federal Prevention of Significant Deterioration air emissions permit issued in accordance with the federal Clean Air Act.

M. "NWF, SR, SJR, SWF, or SF WMD" shall mean the Northwest Florida, Suwannee River, St. Johns River, Southwest Florida, or South Florida Water Management District.

N. "Title V permit" shall mean the federal permit issued in accordance with Title V of the federal Clean Air Act.

IV. GENERAL CONDITIONS

A. Facility Operation

1. The Licensee shall at all times properly operate and maintain the facility and related appurtenances, and systems of treatment and control that are installed and used to achieve compliance with the conditions of this certification, and are required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the approval and when required by Department rules.

2. In the event of a prolonged [thirty (30) days or more] equipment malfunction or shutdown of pollution control equipment, facility operation may be allowed to resume and continue to take place under an appropriate Department order, provided that the licensee demonstrates that such operation will be in compliance with all applicable ambient air quality standards and PSD increments, water quality standards and rules, solid waste rules, domestic wastewater rules and industrial wastewater rules. During such malfunction or shutdown, the operation of the facility shall comply with all other requirements of this certification and all applicable state and federal emission and effluent standards not affected by the malfunction or shutdown.

B. Records Maintained at the Facility

1. These Conditions of Certification or a copy thereof shall be kept at the work site of the approved activity.

2. The licensee shall hold at the facility, or other location designated by this approval, records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation required by this approval, copies of all reports required by this approval, and records of all data used to complete the application for this approval. These materials shall be retained at least three (3) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule. The licensee shall provide copies of these records to the Department upon request. If the licensee becomes aware of relevant facts that were not submitted or were incorrect in any report to the Department, such facts or information shall be promptly submitted or corrected.

C. *Change in Discharge*

All discharges or emissions authorized herein shall be consistent with the terms and conditions of this certification. The discharge of any pollutant not identified in the application, or more frequently than, or at a level in excess of that authorized herein, shall constitute a violation of the certification. Any anticipated facility expansions, production increases, or process modifications which may result in new, different or increased discharges or pollutants, change in fuel, or expansion in steam generating capacity must be reported by submission of a new application for amendment or modification pursuant to Chapter 403.516, F.S.

D. *Noncompliance Notification*

If, for any reason, the licensee does not comply with or is unable to comply with any limitation specified in this certification, the licensee shall notify the Central District Office of the Department by telephone during the working day that said noncompliance occurs. After normal business hours, the licensee shall report any condition that poses a public health threat to the State Warning Point at telephone number (850) 413-9911 or (850) 413-9912. The licensee shall confirm this situation to the DEP District Office in writing within seventy-two (72) hours of becoming aware of such conditions and shall supply the following information:

1. A description of the discharge and cause of noncompliance; and,

2. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and,

3. Steps being taken to reduce, eliminate and prevent recurrence of the non-complying event.

E. *Adverse Impact*

The licensee shall take all reasonable steps to minimize any adverse impact resulting from noncompliance with any limitation specified in this certification, including such accelerated or additional monitoring as necessary to determine the nature and impact of the non-complying event.

F. *Right of Entry*

The licensee shall allow authorized Department personnel, including authorized representatives of the Florida Department of Environmental Protection, Water Management Districts, and/or United States Environmental Protection Agency, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated:

1. To enter upon the licensee's premises where an effluent source is located or in which records are required to be kept under the terms and conditions of this permit; and,

2. To have access to and copy any records required to be kept under the conditions of this certification; and,

3. To inspect and observe the permitted facilities, equipment, practices, or operations regulated or required under these Conditions to determine compliance with the approved plans, specifications and conditions of this certification; and,

4. To sample or monitor any substances or parameters at any location necessary to assure compliance with these Conditions or Department rules.

G. Enforcement

1. The terms, conditions, requirements, limitations and restrictions set forth in these Conditions of Certification are binding and enforceable pursuant to Sections 403.141, 403.161, 403.514,. Any noncompliance with a Condition of Certification or condition of a federally delegated or approved permit constitutes a violation of chapter 403, F.S., and is grounds for enforcement action, permit termination, permit revocation, or permit revision. The Licensee is placed on notice that the Department will review this approval periodically and may initiate enforcement action for any violation of these conditions.

2. All records, notes, monitoring data and other information relating to the construction or operation of this certified source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the certified source arising under the Florida Statutes or Department rules, except where such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

H. Revocation or Suspension

This certification may be suspended or revoked pursuant to Section 403.512, Florida Statutes, or for violations of any of these Conditions of Certification. This approval is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this approval may constitute grounds for revocation and enforcement action by the Department.

I. Civil and Criminal Liability

1. This certification does not relieve the licensee from civil or criminal penalties for noncompliance with any conditions of this certification, applicable rules or regulations of the Department, or Chapter 403, Florida Statutes, or regulations thereunder.

2. This certification does not relieve the licensee from liability for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the licensee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

3. As provided in Subsections 403.087(7), 403.511, and 403.722(5), F.S., the issuance of this certification does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This approval is not a waiver of any other Department approval that may be required for other aspects of the total project under federally delegated programs.

4. Subject to Section 403.511, Florida Statutes, this certification shall not preclude the institution of any legal action or relieve the licensee from any responsibilities or penalties established pursuant to any other applicable State Statutes or regulations.

J. Property Rights

The issuance of this certification does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations. The applicant shall obtain title, lease or right of use from the State of Florida, to any sovereign submerged lands utilized by the project.

K. Severability

The provisions of this certification are severable, and if any provision of this certification, or the application of any provision of this certification to any circumstances, is held invalid, the application of such provision to other circumstances and the remainder of the certification shall not be affected thereby.

L. *Review of Site Certification*

The certification shall be final unless revised, revoked or suspended pursuant to law. At least every five years from the date of issuance of certification the Department will review all monitoring data that has been submitted to it during the preceding five-year period for the purposes of determining the extent of the Licensee's compliance with the conditions of this certification and the environmental impact of this facility. The Department will submit the results of its review and recommendations to the Licensee. Such review will be repeated at least every five years thereafter.

M. *Procedural Rights*

Except as specified in Chapter 403, F.S., or Chapter 62-17, F.A.C., no term or condition of certification shall be interpreted to preclude the post-certification exercise by the licensee of whatever procedural rights it may have under Chapter 120, F.S., including those related to rule-making proceedings.

N. *Modification of Conditions*

The conditions of this certification may be modified in the following manner:

1. The licensee shall comply with rules, adopted by the Department subsequent to the issuance of the certification, which prescribe new or stricter criteria to the extent that the rules are applicable to electric power plants. Except where express variances, exceptions, exemptions, or other relief have been granted, subsequently adopted rules which prescribe new or stricter criteria shall operate as automatic modifications to the certification.

2. The licensee may choose to operate in compliance with any rule subsequently adopted by the Department which prescribes criteria more lenient than the criteria required by the terms and conditions in the certification which are not site specific.

3. The Siting Board hereby delegates to the Secretary of the Department of Environmental Protection the authority to modify, after notice and opportunity for hearing, any conditions pertaining to monitoring or sampling and conditions of Certification pertaining to consumptive use of water, monitoring, sampling, specification of control equipment, related time schedules, effluent or emission standards or limitations, groundwater, mixing zones, zones of discharge, leachate control programs, railroad spur, transmission lines, access roads or pipeline construction, source of treated effluent cooling water, mitigation, transfer or assignment of the Certification or related federally delegated permits, or any special studies conducted , as necessary to attain the objectives of Chapter 403, Florida Statutes,

which are not in conflict with Condition of Certification Part VII.

O. Transfer of Certification

This certification is transferable only upon Department approval in accordance with Section 403.516, F.S., and Rules 62-17.211(3) and 62-730.300, F.A.C., as applicable. The licensee shall be liable for any noncompliance of the approved activity until the transfer is approved by the Department.

P. Safety

The overall design, layout, and operation of the facilities shall be such as to minimize hazards to humans and the environment. Security control measures shall be utilized to prevent exposure of the public to hazardous conditions. The Federal Occupational Safety and Health Standards shall be complied with during construction and operation.

Q. Screening

The Licensee shall provide screening of the site to the extent feasible through the use of aesthetically acceptable structures, vegetated earthen walls and/or existing or planted vegetation

R. Toxic, Deleterious or Hazardous Materials

1. The Licensee shall not discharge to surface waters wastes which are acutely toxic, or present in concentrations which are carcinogenic, mutagenic, or teratogenic to human beings or to significant locally occurring wildlife or aquatic species. The Licensee shall not discharge to ground waters wastes in concentrations which, alone or in combination with other substances, or components of discharges (whether thermal or non-thermal) are carcinogenic, mutagenic, teratogenic, or toxic to human beings (unless specific criteria are established for such components in Section 62-520.420, F.A.C.) or are acutely toxic to indigenous species of significance to the aquatic community within surface waters affected by the ground water at the point of contact with surface waters.

2. The licensee shall report all spills of materials having potential to significantly pollute surface or ground waters and which are not confined to a building or similar containment structure, by telephone immediately after discovery of such spill. The licensee shall submit a written report within forty-eight hours, excluding weekends, from the original notification. The telephone report shall be submitted by calling the

DEP District Office Industrial Wastewater Compliance/Enforcement Section. After normal business hours, the licensee shall contact the State Warning Point by calling (850) 413-9911 or (850) 413-9912. The written report shall include, but not be limited to, a detailed description of how the spill occurred, the name and chemical make-up (include any MSDS sheets) of the substance, the amount spilled, the time and date of the spill, the name and title of the person who first reported the spill, the size and extent of the spill and surface types (impervious, ground, water bodies, etc.) it impacted, the cleanup procedures used and status of completion, and include a map or aerial photograph showing the extent and paths of the material flow. Any deviation from this requirement must receive prior approval from the Department.

S. Noise

Construction noise shall not exceed noise criteria or any applicable requirements of Orange County. The licensee shall notify area residents in advance of the onset and anticipated duration of the steam blowout of the facility's heat recovery steam generator and steam lines. Such steam blowout shall be conducted between 7:00 A.M. and sunset.

T. Flood Control Protection

The plant and associated facilities shall be constructed in such a manner as to comply with the appropriate County flood protection requirements, either by flood proofing or by raising the elevation of the facilities above the 100-year flood level.

U. Historical or Archaeological Finds

If historical or archaeological artifacts, such as Indian canoes, are discovered at any time within the project site, the licensee shall notify the DEP District office and the Bureau of Historic Preservation, Division of Historical Resources, R.A. Gray Building, Tallahassee, Florida 32399, telephone number (850) 487-2073.

V. Endangered and Threatened Species

Prior to start of construction, the licensee shall survey the certified site for endangered and threatened species of animal and plant life. Plant species listed as endangered or threatened by the federal government and plant species listed as endangered by the state shall be transplanted to an appropriate area if practicable. Gopher tortoises and any commensals on the rare or endangered species list shall be relocated after consultation with the FFWCC. A relocation program, as approved by the FFWCC, shall be followed. Entombment of gopher tortoises shall not be allowed.

W. Dispute Resolution

If a situation arises in which mutual agreement cannot be reached between the Licensee and an agency exercising its regulatory jurisdiction, then the matter shall be immediately referred to the Division of Administrative Hearings (DOAH) for disposition in accordance with the provisions of Chapter 120, F.S.

X. Laboratories And Quality Assurance

1. The licensee shall ensure that all laboratory analytical data submitted to the Department, as required by this Certification, are from a laboratory which has a currently valid and Department approved Comprehensive Quality Assurance Plan (CompQAP) or a CompQAP pending approval for all parameters being reported, as required by Chapter 62-160, F.A.C.

2. The licensee shall ensure that all samples required pursuant to this certification are taken by an appropriately trained technician following EPA and Department approved sampling procedures and chain-of-custody requirements in accordance with Rule 62-160, F.A.C. All chain-of-custody records shall be retained on-site for at least three (3) years and made available to the Department immediately upon request.

3. Records of monitoring information shall include:

   a. the date, exact place, and time of sampling or measurements;

   b. the person responsible for performing the sampling or measurements;

   c. the dates analyses were performed;

   d. the person responsible for performing the analyses;

   e. the analytical techniques or methods used; and,

   f. the results of such analyses.

Y. Procedures For Post-Certification Submittals

1. Purpose of Submittals: Conditions of Certification which provide for the post-certification submittal of information to DEP or other agencies by the licensee

are for the purpose of facilitating monitoring by the Department of the effects arising from the plant facilities. This monitoring is for DEP to assure, in consultation with other agencies with applicable regulatory jurisdiction, continued compliance with the conditions of certification, without any further agency action.

2. Filings: All post-certification submittals of information by the licensee are to be filed with DEP. Copies of each submittal shall be simultaneously submitted to any other agency indicated in the specific conditions requiring the post-certification submittals.

3. Completeness: The DEP shall promptly review each post-certification submittal for completeness. This review shall include consultation with the other agencies receiving the post-certification submittal. For the purposes of this condition, completeness shall mean that the information submitted is both complete and sufficient. If the submittal is found to be incomplete, the licensee shall be so notified. Failure to issue such a notice within forty-five (45) days after filing of the submittal shall constitute a finding of completeness.

4. Interagency Meetings: Within sixty (60) days of the filing of a complete post-certification submittal, DEP may conduct an interagency meeting with other agencies which received copies of the submittal. The purpose of such an interagency meeting shall be for the agencies with regulatory jurisdiction over the matters addressed in the post-certification submittal to discuss whether reasonable assurance of compliance with the conditions of certification has been provided. Failure of any agency to attend an interagency meeting shall not be grounds for DEP to withhold a determination of compliance with these conditions nor to delay the time frames for review established by these conditions.

5. Reasonable Assurance of Compliance: Within ninety (90) days of the filing of a complete post-certification submittal, or 45 days after a submittal is made by the licensee, or unless another date is specified herein, DEP shall give written notification to the licensee and the agencies to which the post-certification information was submitted of its determination whether there is reasonable assurance of compliance with the conditions of certification. If it is determined that reasonable assurance has not been provided, the licensee shall be notified with particularity and possible corrective measures suggested. Failure to notify the licensee in writing within ninety (90) days of receipt of a complete post-certification submittal shall constitute a determination of reasonable assurance of compliance.

V. CONSTRUCTION

A. Standards and Review of Plans

1. All construction at the facility shall be pursuant to the design standards presented in the application or amended application and the standards or plans and drawings submitted and signed by an engineer registered in the state of Florida. Specific Central DEP District Office acceptance of plans will be required based upon a determination of consistency with approved design concepts, regulations, and these conditions prior to initiation of construction of any: industrial waste treatment facility; domestic waste treatment facility; potable water treatment and supply system; ground water monitoring system, storm water runoff system; solid waste disposal area; and hazardous or toxic handling facility or area. The Licensee shall present specific plans for these facilities for review by the DEP Central District Office at least ninety (90) days prior to construction of those portions of the facility for which the plans are then being submitted, unless other time limits are specified in the following conditions herein. Review and approval or disapproval shall be accomplished in accordance with Chapter 120, F.S., or these conditions of certification as applicable.

2. The Department must be notified in writing and prior written approval obtained for any material change, modification, or revision to be made to the project during construction which is in conflict with these conditions of certification. If there is any material change, modification, or revision made to a project approved by the Department without this prior written approval, the project will be considered to have been constructed without departmental approval, the construction will not be cleared for service, and the construction will be considered a violation of the conditions of certification.

3. Ninety (90) days prior to the anticipated date of first operation, the Licensee shall provide the Central District and the Siting coordination Office of the Department with an itemized list of any changes made to the facility design and operation plans that would affect a change in discharge as referenced in Condition II. since the time of the approval of these conditions. This pre-operational review of the final design and operation shall demonstrate continued compliance with Department rules and standards.

4. Final drainage plans illustrating all stormwater treatment facilities and conveyances for construction phases and ultimate operations for the entire Curtis H. Stanton Energy Center site shall be submitted to the DEP Central District Manager, the Orange County Pollution Control Department, and the SJRWMD or SFWMD as applicable for review and approval prior to construction of any such conveyance or facility. The Department shall indicate its approval or disapproval within 60 days of the submittal.

B. *Control Measures*

1. To control runoff which may reach and thereby pollute waters of the state, necessary measures shall be utilized to settle, filter, treat or absorb silt containing or pollutant laden storm water to ensure against spillage or discharge of excavated material that may cause turbidity in excess of 29 Nephelometric Turbidity Units (NTU) above background in waters of the state at the POD to Hart Branch or Cowpen Branch. Oil and grease shall not exceed 5 mg/l at any discharge from the makeup water storage supply pond or any other pond. Control measures may consist of sediment traps, barriers, berms, and vegetation plantings. Exposed or disturbed soil shall be protected and stabilized as soon as possible to minimize silt and sediment-laden runoff. The pH of the runoff shall be kept within the range of 6.0 to 8.5. The Licensee shall comply with the applicable nonprocedural requirements in Chapter 62-25, F.A.C.

2. Any open burning in connection with initial land clearing shall be in accordance with Chapter 62-256, F.A.C., Chapter 5I-2, F.A.C., Uniform Fire Code Section 33.101 Addendum, and any other applicable County regulation. Any burning of construction-generated material, after initial land clearing that is allowed to be burned in accordance with Chapter 62-256, F.A.C., shall be reviewed by the DEP Central District office in conjunction with the Division of Forestry and any other county regulations that may apply. Burning shall not occur if not approved by the appropriate agency or if the Department or the Division of Forestry has issued a ban on burning due to fire safety conditions or due to air pollution conditions.

3. Disposal of sanitary wastes from construction toilet facilities shall be in accordance with applicable regulations of the appropriate local health agency. The sewage treatment plant shall be operated in accordance with Chapters 62-600 - 699, F.A.C.

4. Solid wastes resulting from construction shall be disposed of in accordance with the applicable regulations of Chapter 62-701, F.A.C.

5. Construction noise shall not exceed noise criteria or any applicable requirements of Orange County. To mitigate the effects of noise produced by the steam blowout of steam boiler tubes, the licensee shall conduct public awareness campaigns prior to such activities to forewarn the public of the estimated time and duration of the noise.

6. The licensee shall employ proper odor and dust control techniques to minimize odor and fugitive dust emissions. The applicant shall employ control techniques sufficient to prevent nuisance conditions which interfere with enjoyment of residents of adjoining property.

7. Directly associated transmission lines from the facility electric switchyard to existing transmission lines shall be maintained in accordance with the application and the appropriate state and federal regulations concerning use of

herbicides. The Licensee shall notify the Department of the type of herbicides to be used at least 60 days prior to their first use.

8. The licensee shall develop the site so as to retain the buffer of natural vegetation as described in the application and in Condition IV.Q. Screening.

9. Dewatering operations during construction shall be carried out in accordance with Rule 62-621.300(2), F.A.C.

C. Environmental Control Program

An environmental control program shall be established under the supervision of a Florida registered professional engineer or other qualified person to assure that all construction activities conform to applicable environmental regulations and the applicable conditions of certification. If a violation of standards, harmful effects or irreversible environmental damage not anticipated by the application or the evidence presented at the certification hearing are detected during construction, the Licensee shall notify the DEP Central District Office as required by Condition IV. D., Noncompliance Notification.

D. Reporting

Notice of commencement of construction shall be submitted to the Siting Coordination Office and the DEP Central District Office within fifteen (15) days of initiation. Starting three (3) months after construction commences, a quarterly construction status report shall be submitted to the DEP Central District Office. The report shall be a short narrative describing the progress of construction.

E. Pond Perimeter Berms

Construction of the water storage pond perimeter berms shall be in conformance with the provisions of Chapter 62-672, F.A.C, regarding earthen dams, and should be inspected regularly by a licensed engineer.

F. Wetland Vegetation

A non-disturbed area shall be maintained around the oak hardwood swamp area of Hart Branch for a distance of 300 feet during the construction and operating phase of the Stanton Plant.

G. *Stormwater Review*

1. At least ninety days prior to the commencement of construction, the licensee shall provide all information necessary for a complete Environmental Resource Permit application including the engineering drawings and supporting documentation necessary to demonstrate that the stormwater runoff from the proposed project will be treated and attenuated in accordance with Rules 40C-4, 40C-41 and 40C-42, F.A.C. The drawings and documentation shall be signed, sealed and dated by a professional engineer registered in the State of Florida.

2. Prior to the commencement of construction, the Department shall conduct a timely review of the submitted information and request the correction of any errors and omissions and any additional information necessary to complete the application. This shall be done in accordance with timeframes established in Chapter 120.60, F.S. and Rule 62-4.055, F.A.C.

3. The Department shall notify the licensee in writing that the application is complete upon review of all requested information and the correction of any errors or omissions. Construction shall not begin until the Department has provided such written notification.

4. Turbidity and sediments must be controlled to prevent violations of water quality pursuant to Rule 62-302.500, 62-302 .530(70) and 62-4.242 Florida Administrative Code (FAC). Best Management Practices, as specified in the *Florida Stormwater, Erosion and Sedimentation Control Inspectors Manual*, shall be installed and maintained at all locations where the possibility of transferring suspended solids into wetlands and/or surface waters due to the permitted activity. If site-specific conditions require additional measures, then the Applicant shall implement them as necessary to prevent adverse impacts to wetlands and/or surface waters.

5. The existing ambient water quality within Outstanding Florida Waters shall not be lowered as a result of the proposed activity, except as authorized by the FDEP under 62-4.242(2) FAC.

6. At least 90 days prior to start of construction on Unit B a copy of the National Pollutant Discharge Elimination System (NPDES) Notice of Intent (NOI) to use a Construction General Permit (CGP) for stormwater discharges shall be submitted to DEP and a copy shall also be submitted to the Orange County EPD and copied to the Orange County EPD NPDES Administrator.

VI. AIR

A. Permits

The Licensee shall apply for and obtain a revision to any Department issued PSD or Title V permit in accordance with Department Rules in Chapter 620-4.030, Florida Administrative Code, before beginning construction of any planned substantial modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in the applicable portions of Chapter 62-4.030, F.A.C.

B. Existing Units

The construction and operation of all existing units (Units 1,2,A and auxiliary) at the Curtis H. Stanton Energy Center (CHSEC) steam electric power plant site shall be in accordance with all applicable provisions of Chapter 62, Florida Administrative Code including all requirements of the State of Florida State Implementation Plan and approved Title V permit program where applicable. The current Title V Air Operation Permit (0950137-006-AV) is attached as Appendix 1, and is incorporated by reference herein as part of this Certification. In addition, the construction and operation of the units shall be in accordance with 40 CFR Part 60 and the provisions of PSD permits FL-084 and FL-313 and of Air Construction Permits 0950137-008-AC and 0950137-009-AC, incorporated by reference herein as part of this Certification and attached as Appendix 2 and 3 respectively. The provisions of the Title V Air Operation Permit and of the Air Construction Permits shall be conditions of this certification. The licensee shall comply with the substantive provisions and limitations set forth in the Title V Air Operation Permit and the Air Construction Permits as part of these Conditions of Certification, and as those provisions may be modified, amended, or renewed in the future by the Department. Such provisions shall be fully enforceable as conditions of this certification. Any violation of such provisions shall be a violation of these Conditions of Certification.

C. New Units (Unit B)

The terms, conditions, requirements, limitations, and restrictions set forth in draft Permit PSD-FL-373, [Attached as Attachment 4] and any final issuance, modification, or amendment to such PSD permit, are incorporated by reference herein, and are binding and enforceable Conditions of this Certification. The Licensee is subject to and shall comply with the terms, conditions, requirements, limitations, and restrictions set forth in Attachment A and any final issuance modification or amendment thereto. A violation of the terms conditions, requirements, limitations, and restrictions in Appendix A is a violation of these Conditions of Certification. The Licensee is also obligated to comply with any air operation permit issued pursuant to Chapter 62-213, F.A.C.

~~1. The proposed steam generating station shall be constructed and operated in accordance with the capabilities and specifications of the application including, for Unit 1, a 474 (gross), and Unit 2, a 474 (gross) megawatt generating capacity and the 4286 MMBtu/hr heat input rate for each steam generator. For the purpose of calculating mass stack emissions, based on a maximum heat input of 4136 million Btu per hour, stack emissions from CHSEC Unit 1 shall not exceed the following when burning coal:~~

~~a. SO2 - 1.2 lb/million Btu heat input, maximum two hour average, and 1.14 lb/MMBtu maximum three hour average;~~

~~b. NOx - 0.60 lb. per million Btu heat input, 30 day rolling average, except as modified to comply with Unit B Condition VI.J.24.a. below;~~

~~c. Particulates - 0.03 lb per million Btu heat input, 124.1 lb. per hour;~~

~~d. Visible emissions - 20% opacity (6 minute average, except one 6-minute period per hour of not more than 27% opacity).~~

~~2. Based on a maximum heat input of 4286 million Btu per hour, stack emissions from Unit 2 shall not exceed the following when burning coal:~~

~~a.~~

~~SO2~~	~~lb/million Btu heat input~~
~~30 – day rolling average~~	~~0.25~~
~~24 – hour emission rate~~	~~0.67~~
~~3 – hour emission rate~~	~~0.85~~

~~b.~~

~~NOx~~	~~lb/million Btu heat input~~
~~30 – day rolling average~~	~~0.17~~

~~c.~~

~~PM/PM10~~	~~lb/million Btu heat input~~	
	~~lb/MMBtu~~	~~lb/hr~~
~~PM~~	~~0.02~~	~~85.7~~
~~PM10~~	~~0.02~~	~~85.7~~

~~d. CO - 0.15 lb/million Btu heat input, 643 lb/hour.~~

~~e. VOC - 0.015 lb/million Btu heat input, 64 lb/hour.~~

~~f. H2SO4 - 0.033 lb/million Btu heat input 140 lb/hour~~

~~g. Be - 5.2 x 10-6 lb/million Btu heat input, 0.022 lb/hour.~~

~~h. Hg - 1.1 x 10-5 lb/million Btu heat input, 0.046 lb/hour.~~

~~i. Pb - 1.5 x 10-4 lb/million Btu heat input, 0.64 lb/hour.~~

~~j. Fluorides - 4.2 x 10-4 lb/million Btu heat input, 1.8 lb/hour.~~

~~3. The height of the boiler exhaust stack for CHSEC Units 1 & 2 shall not be less than 550 ft. above grade.~~

~~4. Particulate emissions from the coal, lime and limestone handling facilities:~~

~~a. All conveyors and conveyor transfer points will be enclosed to preclude PM emissions (except those directly associated with the coal stacker/reclaimer or emergency stockout, and the limestone stockout for which enclosure is operationally infeasible).~~

~~b. Inactive coal storage piles will be shaped, compacted and oriented to minimize wind erosion.~~

~~c. Water sprays or chemical wetting agents and stabilizers will be applied to storage piles, handling equipment, etc. during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 5 percent, except when adding, moving or removing coal from the coal pile, which would be allowed no more than 20%.~~

~~d. Limestone day silos and associated transfer points will be maintained at negative pressures during filling operations with the exhaust vented to a control system. Lime will be handled with a totally enclosed pneumatic system. Exhaust from the lime silos during filling will be vented to a collector system.~~

~~e. The fly ash handling system (including transfer and silo storage) will be totally enclosed and vented (including pneumatic system exhaust) through fabric filters; and~~

~~f. Any additional coal, lime, and limestone handling facilities for Stanton Unit 2 will be equipped with particulate control systems equivalent to those for Stanton Unit 1.~~

~~5. Particulate emissions from bag filter exhausts from the following facilities shall be limited to 0.02 gr./acf: coal, lime, limestone and flyash handling systems excluding those facilities covered by II/I.A.3.c above. A visible emission reading of 5% opacity or less may be used to establish compliance with this emission limit. A visible emission reading greater than 5% opacity will not create a presumption that the 0.02 gr./acf emission limit is being violated. However, a visible emission reading greater that 5% opacity will require the licensee to perform a stack test for particulate emissions, as set forth in condition VI.D.~~

~~6. Compliance with opacity limits of the facilities listed in Condition~~

~~VI.C. will be determined by EPA referenced method 9 (Appendix A, 40 CFR 60).~~

~~7. Construction shall reasonably conform to the plans and schedule given in the original application or the supplemental application.~~

~~8. The licensee shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the DEP Central District office in Orlando.~~

~~9. Reasonable precautions to prevent fugitive particulate emissions during construction shall be to coat the roads and construction sites used by contractors, and to re-grass or water areas of disturb soils.~~

~~10. Coal shall not be burned in the unit unless the electrostatic precipitator and limestone scrubber and other air pollution control devices are operating as designed except as provided under 40 CFR Part 60, Subpart Da.~~

~~11. Except as noted herein, the fuel oil to be fired in Stanton Units 1 & 2 and the auxiliary boiler shall be primarily "new oil" which means an oil which has been refined from crude oil and has not been used. On-site generated lubricating oil and used fuel oil which meets the requirements of 40 CFR 266.40 may also be burned.~~

~~a. The quality of the No. 2 fuel oil used by the auxiliary boiler shall not contain more than 0.5% sulfur by weight and cause the allowable emission limits listed in the following table to be exceeded. Such emissions may be calculated in accordance with AP-42.~~

~~Allowable Emission Limits~~	
~~Pollutant~~	~~lb/MMBtu~~
~~PM~~	~~0.015~~
~~SO2~~	~~0.51~~
~~NOx~~	~~0.16~~
~~Visible emissions~~	~~Maximum 20% Opacity~~

~~b. Landfill gas from the Orange County Landfill may be burned in Unit No. 1 and Unit No. 2 to the extent that quantities are available provided that all emission limits contained in condition VI.C.1. for Unit 1 and Condition VI.C.2. for Unit 2 are met.~~

~~c. Natural gas as supplied by commercial pipeline may be burned in Unit No. 1 and Unit No. 2 to the extent that quantities are available provided that all emission limits contained in Condition VI.C.1. for Unit 1 and Condition VI.C.2. for Unit 2 are met.~~

~~12. The flue gas scrubber shall be put into service during normal~~

~~operational startup, and shut down when No. 6 fuel oil is being burned. The No. 6 fuel oil shall not contain more than 1.5% sulfur by weight.~~

~~13. No fraction of flue gas shall be allowed to bypass the FGD system to reheat the gases exiting from the FDG system, except that bypass shall be allowed during startup and shutdown.~~

~~14. All fuel oil and coal shipments received shall have an analysis for sulfur content, ash content, and heating value either documented by the supplier or determined by analysis. Coal sulfur content shall be determined and recorded on a daily basis. Records of all the analysis shall be kept for public inspection for a minimum of two years after the data is recorded.~~

~~15. Within 90 days of commencement of operations, the applicant will determine and submit to FDER the pH level range in the scrubber reaction tank that correlates with the specified limits for SO2 in the flue gas. Moreover, the applicant is required to operate a continuous pH meter equipped with an upset alarm to ensure that the operator becomes aware when the pH level of the scrubber reaction tank falls out of this range. The pH monitor can also act as a backup in the event of malfunction of the continuous SO2 monitor. The value of the scrubber pH may be revised at a later date provided notification to FDER is made demonstrating the emission limit is met. Further, if compliance data show that higher FGD performance is necessary to maintain the emission limit, a different pH value will be determined and maintained.~~

~~16. The applicant will comply with all requirements and provisions of the New Source Performance standard for electric utility steam generating units (40 CFR 60 Part Da).~~

~~17. The Licensee shall submit to the Department at least 120 days prior to start of construction of the NOx control system, copies of technical data pertaining to the selected NOx control system. These data, if applicable to the technology chosen by the Licensee, should include but not be limited to design efficiency, guaranteed efficiency, emission rates, low rates, reagent injection rates, or types of catalysts. The Department may, upon review of these data, disapprove the use of any such device or system if the Department determines the selected control device or system to be inadequate to meet the emission limits specified in I.b. above. Such disapproval shall be issued within 90 days of receipt of the technical data.~~

~~18. Concrete Batch Plant~~

~~a. For the operation of a Vince Hagan Company Model HSM-10250C-400 concrete batch plant with cement and fly ash storage silos, emissions generated during pneumatic drilling of storage silos will be controlled by two Vince Hagan Company Model ES-268B baghouses, one on each silo, with 268 square feet of cloth filtration area. A water spray ring will be used to control emissions during truck loading.~~

~~b. Visible emissions from concrete batching plants, silos, hoppers and other storage or conveying equipment shall not exceed 5% opacity (Rule 62-296.414(1), F.A.C.).~~

~~c. The initial and subsequent compliance tests for visible emissions on the particulate matter control equipment shall be conducted using DEP Method 9 in accordance with Rule 62-297.401(9)(c), F.A.C. The initial and subsequent compliance tests for visible emissions on the storage piles shall be conducted using EPA Method 22 in accordance with Rule 62-297.401(22), F.A.C., and 40 CFR 60, appendix A. The Department's Central District office shall be notified in writing at least 15 days prior to the compliance test in accordance with Rule 62-297.310(7)a)9, F.A.C. The test reports shall be submitted to the Department's Central District office no later than 45 days after the last sampling run of each test is completed in accordance with Rule 62-297.310(8)(b), F.A.C.~~

~~d. The visible emissions test observation period shall include the period during which the highest opacity can reasonably be expected to occur. For the storage silos, this is expected to be the last 30 minutes of filling.~~

~~e. Testing of emissions must be accomplished while filling the cement and fly ash storage silos within ± 10% of the permitted capacity of 27 tons per hour. A compliance test submitted at operating rates less than 90% of the permitted capacity will automatically constitute an amended permit at the lesser rate. Failure to submit the input rates and actual operating conditions may invalidate the test (Rule 62-297.310(8)(c), F.A.C.).~~

~~f. Permitted hours of operation are up to 20 hrs/day, seven days per week, and not to exceed 4,200 hrs/year.~~

~~g. All reasonable precautions shall be taken to prevent and control generation of unconfined emissions of particulate matter in accordance with the provision in rule 62-296.320(4), F.A.C. These provisions are applicable to any source, including, but not limited to, vehicular movement, transportation of materials, construction, alteration, demolition or wrecking, or industrial related activities such as loading, unloading, storing and handling. Reasonable precautions shall include the use of water sprinklers to prevent and control fugitive particulates from plant grounds and aggregate storage piles and the use of the water spray ring at the truck loadout.~~

~~D. Air Monitoring Program~~

~~1. A flue gas oxygen meter shall be installed for Stanton Unit 2 to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously maintain air/fuel ratio parameters at an optimum. The flue gas manufacturing oxygen monitor shall be~~

~~calibrated and operated according to established procedures as approved by DEP. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" may be used as a guide.~~

~~2. The licensee shall install and operate continuous monitoring devices for Stanton Unit 2 main boiler exhaust for sulfur dioxide, nitrogen oxides, oxygen, and opacity. The monitoring devices shall meet the applicable requirements of Section 62-296.405(1)(f), FAC., and 40 CFR 60.47a. The opacity monitor may be placed in the ductwork between the electrostatic precipitator and the FGD scrubber.~~

~~3. The licensee shall maintain a daily log of the amounts and types of fuel used. The log shall be kept for inspection for at least two years after the data is record. Fuel analysis data including sulfur content, ash content, and heating values shall be determine on an as received basis and kept for two years.~~

~~4. The licensee shall provide stack sampling facilities as required by Rule 62-297.310(6), F.A.C.~~

~~***E. Stack Testing***~~

~~1. Within 60 calendar days after achieving the maximum capacity at which unit 2 will be operated, but no later than 180 operating days after initial startup, the licensee shall conduct performance tests for particulates, SO2, NOx, and visible emissions during formal operations near (±10%) 4286 MMBtu/hr heat input and furnish the Department a written report the results of such performance tests within 45 days of completion of the tests. The performance test will be conducted in accordance with the provisions of 40 CFR 60.46a and 48a.~~

~~2. Compliance with emission limitation standards mentioned in specific condition No. VI.B. shall be demonstrated during the initial performance test using appropriate EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), or any method as proposed by the Applicant and approved by the Department, in accordance with F.A.C. Rule 62-297.~~

~~EPA Method~~	~~For Determination Of~~
~~1~~	~~Selection of sample site and velocity traverses.~~
~~2~~	~~Stack gas flow rate when converting concentration to or from mass emission limits.~~
~~3~~	~~Gas analysis when needed for calculation of molecular weight or percent O2.~~
~~4~~	~~Moisture contents when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission~~

	~~limits.~~
~~5~~	~~Particulate matter concentration and mass emissions.~~
~~201 or 201A~~	~~PM10 emissions.~~
~~6, 6C, or 19~~	~~Sulfur dioxide emissions from stationary sources.~~
~~7, 7C, or 19~~	~~Nitrogen oxide emissions from stationary sources.~~
~~9~~	~~Visible emission determination of opacity.~~ ~~-At least three one hour runs to be conducted simultaneously with particulate testing for the emissions from dry scrubber/baghouse, and ash handling building baghouse.~~ ~~-At least one lime truck unloading into the lime silo (from start to finish).~~
~~10~~	~~Carbon monoxide emissions from stationary sources.~~
~~12 or l0lA~~	~~Lead concentration from stationary sources.~~
~~13A or 13B~~	~~Fluoride emissions from stationary sources.~~
~~18, 25, 25A or 25B~~	~~Volatile organic compounds concentration.~~
~~l0lA or 108~~	~~Mercury emissions.~~
~~104~~	~~Beryllium emission rate and associated moisture content.~~

~~3. The licensee shall provide 30 days written notice of the performance tests for continuous emission monitors or 10 working days written notice for stack tests in order to afford the Department the opportunity to have an observer present.~~

~~4. Stack tests for particulates NOx and SO2 and visible emissions shall be performed annually.~~

~~***F. Reporting***~~

~~1. For Stanton Unit 2, a summary in the EPA format of stack continuous monitoring data, fuel usage and fuel analysis data shall be reported to the Department's Central District Office and to the Orange County Environmental Protection Department on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Section 60.7, and 60.49a.~~

~~2. Beginning one month after certification, the licensee shall submit to the Department a quarterly status report briefly outlining progress made on engineering and design and purchase of major of pieces of air pollution control equipment. All reports and information required to be submitted under this condition shall be submitted to the Siting Coordination Office, Department of Environmental Protection, 2600 Blair Stone Road MS 48, Tallahassee, 32399-2400.~~

~~G. Malfunction or Shutdown~~

~~In the event of a prolonged (thirty days or more) equipment malfunction or shut down of air pollution control equipment, operation may be allowed to resume or continue to take place under appropriate Department order, provided that the Licensee demonstrates such operation will be in compliance with all applicable ambient air quality standards and PSD increments. During such malfunction or shutdown, the operation of Stanton Unit 2 shall comply with all other requirements of this certification and all applicable state and federal emission standard not affected by the malfunction or shutdown which is the subject of the Department's order. Exceedances produced by operational conditions for more than two hours due to upsets in air pollution control systems as a result of start-up, shutdown, or malfunctions as defined by 40 CFR 60 need not be reported as specified in Condition IV.D. Identified operational malfunctions which do not stop operation but prevent compliance with emission limitations shall be reported to DEP as specified in Condition IV.D.~~

~~H. Open Burning~~

~~Open burning in connection with initial land clearing shall be in accordance with chapter 62-256, F.A.C., Chapter 5I-2, F.A.C., Uniform Fire Code Section 33.101 Addendum, and any other applicable County regulation.~~

~~Any burning of construction generated material, after initial land clearing, that is allowed to be burned in accordance with Chapter 62-256, F.A.C., shall be approved by the DEP Central District Office in conjunction with the Division of Forestry and any other County regulations that may apply. Burning shall not occur unless approved by the jurisdictional agency or if the Department or the Division of Forestry has issued a ban on burning due to fire safety conditions or due to air pollution conditions.~~

~~I. Combined Cycle Unit A~~

~~For Combined Cycle Unit A Licensee shall comply with all limitations, restrictions, and conditions contained in PSD permit number PSD-FL-313. The PSD permit is included in and made part of these Conditions of Certification as follows:~~

~~1. Emissions Units~~

~~This permit addresses the following emissions units:~~

~~Emission Unit~~	~~System~~	~~Emission Unit Description~~
~~025~~	~~Power Generation~~	~~One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a~~

		~~combined cycle unit, complete with supplementary fired HRSG~~
~~026~~	~~Power Generation~~	~~One nominal 170 Megawatt Gas Combustion Turbine- Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG~~
~~027~~	~~Water Cooling~~	~~One 10 cell mechanical draft Cooling Tower~~
~~028~~	~~Fuel Storage~~	~~One 1,680,000 Gallon Distillate Fuel Oil Storage Tank~~

~~2. Regulatory Classification~~

~~The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM10), sulfur dioxide (SO2), nitrogen oxides (NOX), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).~~

~~This facility is within an industry (fossil fuel-fired steam electric plant) included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of SO2 and NOx, 25/15 TPY of PM/PM10, 100 TPY of CO and 40 TPY of VOC's. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.~~

~~This project is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting. [Chapter 403.503(12), F.S., Definitions]~~

~~Based on the Title V permit, this facility is not currently a major source of hazardous air pollutants (HAPs). This facility is subject to certain Acid Rain provisions of Title IV of the Clean Air Act.~~

~~3. Relevant Documents:~~

~~The documents listed below are the basis of the permit. They are specifically related to this permitting action, but are not incorporated into this permit. These documents are on file with the Department.~~

~~Application received on January 22, 2001.~~

~~Letter from Fish & Wildlife Service dated February 9, 2001.~~

~~Additional information received from applicant on May 1, 2001.~~

~~Department's Intent to Issue and Public Notice Package dated May 17, 2001.~~

~~Department's Draft Permit and Draft BACT determination dated May 17, 2001.~~

~~Letter from EPA Region IV~~

~~Site Certification for the Stanton A Combined Cycle addition~~

~~Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.~~

~~4. General And Administrative Requirements~~

~~**Regulating Agencies**: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767 and phone number 407/894-7555.~~

~~**General Conditions**: The owner and operator is subject to and shall operate under the General Permit Conditions G.1 through G.15 listed in Appendix GC of the permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]~~

~~**Terminology**: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.~~

~~**Forms and Application Procedures**: The licensee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]~~

~~**Modifications**: The licensee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]~~

~~**Expiration**: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]~~

~~**BACT Determination**: In accordance with paragraph (4) of 40 CFR 52.21(j) and 40 CFR 51.166(j), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 52.21(j), 40 CFR 51.166(j) and Rule 62-4.070 F.A.C.]~~

~~**Permit Extension**: The licensee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit. In conjunction with extension of the 18-month periods to commence or continue construction, or extension of the December 31, 2004 permit expiration date, the licensee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.080, F.A.C.]~~

~~**Application for Title IV Permit**: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]~~

~~**Application for Title V Permit**: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Central District Office. [Chapter 62-213, F.A.C.]~~

~~**New or Additional Conditions**: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the licensee to conform to new or additional conditions. The Department shall allow the licensee a reasonable time to conform to the new or additional conditions, and on application of the licensee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]~~

~~**Annual Reports**: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the licensee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Central District Office by March 1st of each year.~~

~~**Stack Testing Facilities**: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.~~

~~**Quarterly Reports**: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Central District Office.~~

~~5. Applicable Standards And Regulations~~

~~Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.~~

~~**NSPS Requirements**: Each combustion turbine (CT) shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.~~

~~**Subpart A, General Provisions**, including: 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).~~

~~**Subpart GG, Standards of Performance for Stationary Gas Turbines;** see attached *Appendix GG*.~~

~~Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]~~

~~These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:~~

~~40CFR60.7, Notification and Recordkeeping~~

~~40CFR60.8, Performance Tests~~

~~40CFR60.11, Compliance with Standards and Maintenance Requirements~~

~~40CFR60.12, Circumvention~~

~~40CFR60.13, Monitoring Requirements~~

~~40CFR60.19, General Notification and Reporting requirements~~

~~ARMS Emissions Units 025 and 026. Direct Power Generation, each consisting of a nominal 170 megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). Additionally, each Emissions Unit consists of a supplementally fired heat recovery steam generator equipped with a natural gas fired 533 MMBTU/hr duct burner (LHV) and combined with a nominal 300 MW steam electrical generators. These shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.~~

~~ARMS Emission Unit 027. Cooling Tower, an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because chromium-based chemical treatment is not used.~~

~~ARMS Emission Unit 028. Fuel Storage Tank, consisting of a 1,680,000-gallon distillate fuel storage tank. The storage tank is subject to 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984.~~

~~All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District Office.~~

~~6. General Operation Requirements~~

~~**Fuels**: Only pipeline natural gas or (up to) 1000 hours per year of 0.05% distillate fuel oil shall be fired in each CT emissions unit. Only natural gas shall be fired in each duct burner. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]~~

~~**Combustion Turbine Capacity**: The maximum heat input rates to each CT/HRSG shall not exceed 2,402 million Btu per hour (MMBtu/hr) when firing natural gas with duct burner firing and power augmentation. The maximum heat input~~

~~rates to each CT/HRSG shall not exceed 2,068 million Btu per hour (MMBtu/hr) when firing fuel oil. These maximum heat input rates shall not be exceeded under any condition, regardless of ambient conditions or combustion turbine characteristics. Manufacturer's curves corrected for ISO conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]~~

~~**Heat Recovery Steam Generator equipped with Duct Burner**: The maximum heat input rate of the natural gas fired duct burner shall not exceed 533 MMBtu/hour (LHV) at any temperature or under any scenario. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]~~

~~**Unconfined Particulate Emissions**: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.~~

~~**Plant Operation - Problems**: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Central District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the licensee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]~~

~~**Operating Procedures**: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]~~

~~**Circumvention**: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]~~

~~**Maximum allowable hours** of operation for each CT/HRSG Emissions Unit are 8760 hours per year while firing natural gas. Fuel oil firing is permitted for 1000 hours during any consecutive 12-month period in each CT. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]~~

~~**Simple Cycle Operation**: The plant may not be operated without the use of the SCR system except during periods of startup and shutdown.~~

~~7. Control Technology~~

~~Dry Low NOX (DLN) combustors and water injection capability shall be installed on each stationary combustion turbine. The licensee shall install a selective catalytic reduction system to comply with the NOX and ammonia limits listed in Specific Condition 21. Additionally, space shall be provided for the installation of oxidation catalysts. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]~~

~~The licensee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 21 through 25. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]~~

~~Drift eliminators shall be installed on the cooling tower to reduce PM/PM10 emissions. A certification following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002 gallons/100 gallons recirculation water flowrate.~~

~~8. Emission Limits And Standards~~

~~**Nitrogen Oxides (NOX) Emissions:**~~

~~The concentration of NOX in the stack exhaust gas, with the combustion turbine operating on natural gas shall not exceed 3.5 ppmvd @15% O2 on a 3-hr block average. This limit shall apply whether or not the unit is operating with duct burner on and/or in power augmentation mode. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]~~

~~The emissions of NOX in the stack exhaust gas, with the combustion turbine operating on fuel oil shall not exceed 10.0 ppmvd @15% O2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]~~

~~Emissions of NOX from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition 30 for compliance procedures). [Applicant Request, Rule 62-4.070 and 62-204.800(7), F.A.C.]~~

~~The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 5.0 ppmvd @15% O2. The compliance procedures are described in Specific Conditions 29 and 45. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]~~

~~**Carbon Monoxide (CO) Emissions**: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on natural gas shall not exceed 17 ppmvd @15% O2 on a 24-hr block average to be demonstrated by CEMS; and neither 14 ppmvd @15% O2 with the CT operating on fuel oil on a 24-hr block average to be demonstrated by CEMS. These limits shall also be demonstrated~~

~~by annual stack test using EPA Method 10 or through annual RATA testing. Within 24 months of the date of completion of initial testing, the applicant shall either have installed oxidation catalyst in each CT/HRSG or forfeit its right to do so with the pre-determined (BACT) emission limits specified below. [BACT, Rule 62-212.400, F.A.C.]~~

~~In the event that an oxidation catalyst is installed for any reason in either CT/HRSG pair within 24 months of the date of completion of initial testing, the limits for CO and VOC shall be 5 ppmvd and 3 ppmvd (respectively) to be demonstrated by stack testing during power augmentation and duct burner firing (I, A). [BACT]~~

~~**Volatile Organic Compounds (VOC) Emissions**: Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall exceed neither 2.7 ppmvd @15% O2 with the CT firing fuel oil and neither 6.3 ppmvd @15% O2 with the CT firing natural gas (with maximum duct burner firing and operating in power augmentation mode); to be demonstrated by initial stack tests using EPA Method 18, 25 or 25A. [BACT, Rule 62-212.400, F.A.C.]~~

~~**Sulfur Dioxide (SO2) emissions**: SO2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 1.5 grains per 100 standard cubic foot) and up to 1000 hours per consecutive 12-month period of 0.05% sulfur fuel oil. Compliance with these fuel limits in conjunction with implementation of the attached Appendix GG will demonstrate compliance with the applicable NSPS SO2 emissions limitations from the duct burner and the combustion turbine. Note: This will effectively limit the combined SO2 emissions for EU-025 and EU-026 to approximately 134 tons per year. [BACT, 40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]~~

~~**PM/PM10 and Visible emissions (VE)**: VE emissions shall not exceed 10 percent opacity from the stack in use. [BACT, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]~~

~~9. Excess Emissions~~

~~**Excess emissions** resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during a "cold start-up" to combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 72 hours. Operation below 50% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [BACT, Rule 62-210.700, F.A.C.].~~

~~**Excess emissions** entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-~~

~~210.700, F.A.C. These emissions shall be included in the 3-hr average for NOX and the 24-hr average for CO.~~

~~**Excess Emissions Report**: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions 41 through 45, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 21 through 25. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].~~

~~10. Compliance Determination~~

~~Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.~~

~~Initial (I) performance tests shall be performed by the deadlines in Specific Condition 29. Initial tests shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or addition of oxidation catalyst (or change of combustors, if specifically requested by the DEP on a case-by-case basis). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.~~

~~EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).~~

~~EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).~~

~~EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test~~

~~requirement) shall be conducted a) while firing natural gas with maximum duct burner heat input as well as maximum power augmentation and b) while firing fuel oil at the maximum heat input; Initial test for compliance with 40CFR60 Subpart GG; Initial (only) NOX compliance test for the duct burners (Subpart Da) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.~~

~~__________ EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.~~

~~__________ EPA Method 0011 or CARB Method 430 shall be utilized to evaluate the emissions of formaldehydes on each CT/Duct Burner as per the table below. A full report including all test results, analyses and applicant's MACT Determination shall be forwarded to the Bureau of Air Regulation in Tallahassee within the same time constraints identified in Specific Condition G.29.~~

~~OPERATING MODE~~	~~TEST PROTOCOL~~	~~TPY CALCULATION~~
~~Maximum CT output Natural Gas; Duct Burner firing at maximum output~~	~~CARB Method 430 or EPA Method 0011~~	~~(6760/2000) times measured Lb/Hour Formaldehyde~~
~~Maximum CT output Natural Gas; Duct Burner firing and Power Augmentation implemented, both at max. output~~	~~CARB Method 430 or EPA Method 0011~~	~~(1000/2000) times measured Lb/Hour Formaldehyde~~
~~Maximum output, Fuel Oil~~	~~CARB Method 430 or EPA Method 0011~~	~~(1000/2000) times measured Lb/Hour Formaldehyde~~

~~Note: Results of the sampling method(s) identified above shall be blank corrected. For Method 0011, a minimum sample volume of 30 cubic feet shall be collected. To improve test precision, there shall be two co-located trains for each test. A minimum of 3 runs per CT/Duct Burner shall constitute a test.~~

~~__________ Method CTM-027 for ammonia slip (I, A) to be completed simultaneously with NOX compliance testing.~~

~~__________ The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O2) at the measured lb/hr NOX emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition 45.~~

~~__________ **Continuous compliance with the CO and NOX emission limits**: Continuous compliance with the CO and NOX emission limits shall be demonstrated by the CEM system on the specified hour average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Specific Condition 41 further describes the CEM system requirements. Excess emissions periods shall be reported as required in Condition 28. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]~~

~~__________ **Compliance with the SO2 and PM/PM10 emission limits**: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO2 standard, the applicant is responsible for ensuring that the procedures outlined in attached Appendix~~

~~GG are complied with.~~

~~**Compliance with CO emission limit**: An initial and annual test for CO shall be conducted at 100% capacity with the duct burners off. The NOX and CO test results shall be the average of three valid one-hour runs. Annual RATA testing for the CO and NOX CEMS shall be required pursuant to 40 CFR 75.~~

~~**Compliance with the VOC emission limit**: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit will be employed as a surrogate and no annual testing is required [see Specific Condition 22 for exception].~~

~~**Testing procedures**: Unless otherwise specified, testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.~~

~~**Test Notification**: The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance tests.~~

~~**Special Compliance Tests**: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, odors or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.~~

~~**Test Results**: Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].~~

~~11. Notification, Reporting, And Recordkeeping~~

~~**Records**: All measurements, records, and other data required to be maintained by the applicant shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.~~

~~The applicant will be required to maintain records indicating the daily hours of operation of each CT/HRSG unit. These records shall specify which type of fuel is being combusted and the records shall be available for review at the site. Each calendar month, a compilation of the hours of operation for each CT/HRSG unit combusting fuel oil shall be made and totalized for the most recent consecutive 12-month period. Each AOR submitted by the applicant shall include a compilation of each consecutive 12-month period during the preceding calendar year.~~

~~**Compliance Test Reports**: The test report shall provide sufficient~~

~~detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.~~

~~**Continuous Monitoring System**: The licensee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the emissions of NOX and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NOX and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NOX and CO established in this permit. Compliance with the emission limits for NOx shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.~~

~~The NOX monitor shall be certified and operated in accordance with the following requirements. The NOX monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 3-hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NOX monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NOX monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O2.~~

~~The CO monitor and CO2 monitor shall be certified and operated in~~

~~accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to the Department's Central District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 20 ppm, and the span for the upper range shall not be greater than 100 ppm, as corrected to 15% O2. The RATA tests required for the CO2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.~~

~~NOX, CO and CO2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NOX and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit. Periods of data excluded for startup shall not exceed two hours in any block 24-hour period except for "cold startup." A cold startup is defined as a startup following a complete shutdown lasting a minimum of 72 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block period. Periods of data excluded for malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all startup, shutdown or malfunction episodes shall not exceed four hours in any 24-hour block period. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.~~

~~Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.~~

~~A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported to the Department's Central District office semi-annually, and shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess~~

~~emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur.~~

~~Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. [Rules 62-4.070(3) and 62-212.400., F.A.C., and BACT]~~

~~[Note: Compliance with these requirements will ensure compliance with the other CEM system requirements of this permit to comply with Subpart GG requirements, as well as the applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.7(a)(5) and 40 CFR 60.13, and with 40 CFR Part 51, Appendix P, 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60, Appendix F, Quality Assurance Procedures].~~

~~Continuous Monitoring System Reports~~~~: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Bureau of Ambient Monitoring & Mobile Sources (BAMMS) as well as the EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.~~

~~Determination of Process Variables~~~~: The licensee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. No later than 90 days prior to operation, the licensee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition.~~

~~Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]~~

~~Subpart Da Monitoring and Recordkeeping Requirements~~~~: The licensee shall comply with all applicable requirements of this Subpart [40CFR60,~~

~~Subpart Da].~~

~~Selective Catalytic Reduction System (SCR) Compliance Procedures:~~

~~An annual stack emission test for nitrogen oxides and ammonia from the CT/HRSG pair shall be simultaneously conducted while operating in the power augmentation mode with the duct burner on as defined in Specific Condition 21. The ammonia injection rate necessary to comply with the NOX standard shall be established and reported during the each performance test.~~

~~The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by manufacturer's guidelines and in accordance with this permit.~~

~~The licensee shall install and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of the CT/HRSG set. It shall be maintained and calibrated according to the manufacturer's specifications.~~

~~During the stack test, the licensee (at each tested load condition) shall determine and report the ammonia flow rate required to meet the emissions limitations. During NOX CEM downtimes or malfunctions, the licensee shall operate at the ammonia flow rate, which was established during the last stack test.~~

~~Ammonia emissions shall be calculated continuously using inlet and outlet NOX concentrations from the SCR system and ammonia flow supplied to the SCR system. The calculation procedure shall be provided with the CEM monitoring plan required by 40CFR Part 75. The following calculation represents one means by which the licensee may demonstrate compliance with this condition:~~

~~Ammonia slip @ 15%O2 = (A-(BxC/1,000,000)) x (1,000,000/B) x D,~~

~~where:~~

~~A= ammonia injection rate (lb/hr)/ 17 (lb/lb. mol)~~

~~B = dry gas exhaust flow rate (lb/hr) / 29 (lb/lb. mol)~~

~~C = change in measured NOX (ppmv@15%O2) across catalyst~~

~~D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip~~

~~The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device utilized to make the ammonia emission measurement and submitted with each annual compliance test.~~

~~Upon specific request by the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements, in~~

~~order to demonstrate that all NOX and ammonia slip related permit limits can be complied with.~~

~~12. NSPS Subpart GG Requirements~~

~~[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in bold immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]~~

~~**Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:**~~

~~(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:~~

~~(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:~~

$$\cancel{STD = 0.0075\frac{(14.4)}{Y} + F}$$

~~where:~~

~~STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).~~

~~Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.~~

~~F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of this section.~~

~~(3) F shall be defined according to the nitrogen content of the fuel as follows:~~

~~**Fuel-bound nitrogen (percent by weight)**~~	~~**F (NOx percent by volume)**~~
~~N≤0.015~~	~~0~~
~~0.015<N≤0.1~~	~~0.04(N)~~

~~0.1<N≤0.25~~	~~0.004+0.0067(N−0.1)~~
~~N>0.25~~	~~0.005~~

~~Where, N = the nitrogen content of the fuel (percent by weight).~~

~~**Department requirement:** While firing gas, the "F" value shall be assumed to be 0.~~

~~[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit are more stringent than this requirement.]~~

~~(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.~~

~~**Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide**~~:

~~On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:~~

~~(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel, which contains sulfur in excess of 0.8 percent by weight.~~

~~**Pursuant to 40 CFR 60.334 Monitoring of Operations:**~~

~~(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:~~

~~(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.~~

~~**Department requirement:** The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.~~

~~[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]~~

~~(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.~~

~~**Department requirement**: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.~~

~~[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]~~

~~(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:~~

~~(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).~~

~~**Department requirement**: NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.~~

~~[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]~~

~~(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.~~

~~**Pursuant to 40 CFR 60.335 Test Methods and Procedures:**~~

~~(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.~~

~~(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.~~

~~(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:~~

~~(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:~~

~~NOx = (NOxo) (Pr/Po) 0.5 e 19(Ho—0.00633) (288°K/Ta) 1.53~~

~~where:~~

~~NOx = emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.~~
~~NOxo = observed NOx concentration, ppm by volume.~~
~~Pr = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.~~
~~Po = observed combustor inlet absolute pressure at test, mm Hg.~~
~~Ho = observed humidity of ambient air, g H2O/g air.~~
~~e = transcendental constant, 2.718.~~
~~Ta = ambient temperature, °K.~~

~~**Department requirement**: The owner or operator is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.~~

~~[Note: This is consistent with guidance from EPA Region 4.]~~

~~(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations~~

~~supplied by the manufacturer.~~

~~**Department requirement**: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.~~

~~[Note: This is consistent with guidance from EPA Region 4.]~~

~~(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.~~

~~**Department requirement**: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.~~

~~[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]~~

~~(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference—see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.~~

~~**Department requirement**: The permit specifies sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.~~

~~[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]~~

~~(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may~~

~~be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.~~

~~[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]~~

VII. WETLANDS RESOURCE MANAGEMENT

A. The proposed transmission line from the Stanton Energy Center to the Mud Lake transmission line and the proposed alternate access road to the Stanton Energy Center from the south shall be routed as shown in the supplemental application. Prior to construction, the licensee shall submit drawings on 8.5" by 11" paper, showing the final design, including plan views and cross-sections for each area of filling or clearing in wetlands. The drawings shall show the existing and proposed ground elevations and all existing and proposed structure location, sizes and invert elevations.

B. All clearing and construction activities shall be confined to the limits of the clear zone necessary for the transmission line as shown on Figures 6.1-5 and 6.1-6 of the application drawings. Within 30 days of the completion of construction, the licensee shall arrange a site visit by DEP District personnel from the Central District office in Orlando to verify that no wetland damage has occurred outside the transmission line clear zone. If wetland damage occurs outside the transmission line clear zone during construction, the licensee shall submit to the DEP Central District Office for review a plan to restore the wetland area which was damaged and to provide mitigation for the damage. The plan shall be implemented within 30 days of the Department approving the restoration and mitigation plan. This condition does not preclude the Department from taking enforcement action if unauthorized activities occur.

C. Prior to initiating construction, the licensee shall submit a map and aerial photographs showing the location of all staging areas for the transmission line and alternate access road construction to the DEP's Central District Office for review and written approval. These areas shall be upland areas which are not currently providing red-cockaded woodpecker nesting or foraging habitat. The staging areas shall not be used prior to receiving DEP approval.

D. Drainage structures shall be placed in the transmission line ROW and under the alternate access road at the same locations where drainage structures currently exist under the CSX Railroad berm. The drainage structures shall provide at least the same efficiency as the corresponding drainage structure currently existing in the CSX Railroad berm.

E. The forested areas to be cleared shall be cleared using low-impact equipment so as to minimize soil disturbance. The rootmats and tree stumps shall be left in place to provide soil stabilization.

F. During construction, best management practices, including but not limited to staked hay bales and filter cloth, shall be utilized to control erosion and turbidity. All side slopes shall be seeded and mulched within 72 hours of the final grading.

G. Construction of the transmission line and alternate access road will result in the filling of 4.12 ac. of the herbaceous wetlands the permanent clearing of 13.19 ac. of forested wetlands. The licensee shall provide mitigation to offset the wetland loss and habitat degradation resulting from the construction of this project. Prior to construction, the licensee shall propose a mitigation plan and shall provide the following information to the DEP Central District Office to allow the Department to review the proposed mitigation plan:

1. detailed description of each wetland impact area;

2. acreage of the type and quality of wetland being impacted at each site;

3. narrative, drawings and aerial photographs showing and explaining the proposed mitigation;

4. detailed description of the existing conditions at the mitigation area;

5. acreage of the proposed mitigation by mitigation and wetland type;

6. documentation providing reasonable assurance that the proposed mitigation will be successful.

If the mitigation submittal is deemed by the Department to provide insufficient information for review, additional information requested by the Department shall be submitted. Upon receiving complete information, the Department will assess the mitigation plan within 90 days.

If the Department, upon review of the proposed mitigation, determines that the proposed mitigation is inadequate to offset the wetland loss and habitat degradation from this project, the licensee shall propose additional mitigation.

H. Combined Cycle Unit A Transmission Line

1. Within 90 days after receiving certification, the Licensee shall meet with the DEP Central District Office and Orange County to discuss alternative routes for the on-site transmission line from Unit A to the Stanton Energy Center Substation with the intent to minimize impacts on the cypress dome in Wetland 3.

2. Once the final route has been established for the transmission line the applicant/licensee shall proposed mitigation to offset the proposed wetland impacts.

3. Prior to construction of work authorized by this certification, the licensee shall provide written notification of the date of commencement of construction to the Central District Office of the Florida Department of Environmental Protection, 3319 Maguire Boulevard, Suite 232, Orlando, FL 32803-3767.

4. Turbidity controls shall be utilized around the entire work area. The turbidity controls shall be maintained throughout the duration of the project, and shall be effective in preventing soil from the fill pad from eroding into the adjacent wetlands and conservation easement.

5. Within 30 days of completion of work authorized by this certification, the licensee shall provide written notification of the date of completion of construction to the Central District Office of the Florida Department of Environmental Protection, 3319 Maguire Boulevard, Suite 232, Orlando, FL 32803-3767.

6. The limits of construction within the wetlands shall be delineated by a continuous plastic flagging tape and with a turbidity barrier/control. The licensee shall bear the responsibility of notifying all construction workers that the flagging and barriers represent the limits of all construction activities. The licensee shall bear the responsibility of keeping all construction workers and equipment out of the wetland or surface water areas, which has not been permitted for impacts.

7. There shall be no storage or stockpiling of tools or materials within the wetlands.

8. If any damage occurs to wetlands or surface waters as a result of any construction activities, the licensee shall be required to restore the wetland area(s) or surface waters by regrading the damaged areas back to the natural preconstruction elevations and planting vegetation of the size, densities and species that exist in the adjacent areas pursuant to a consent order. The restoration shall be completed within 30 days of completion of the construction and shall be done to the satisfaction of the Department.

9. All material used as fill shall be clean material and shall not be contaminated with vegetation, garbage, trash, tires, hazardous, toxic waste or other materials that are not suitable for road construction within waters of the State as so determined by the Department.

10. The fill and associated side slopes (for example for the key-hole pads) that will be placed in wetlands on the property shall be stabilized with sod immediately (within 48 hours) following completion of the placement and compaction of the fill material.

I. The project shall comply with applicable state water quality standards, including:

1. 62-302.500 - minimum criteria for all surface waters at all places and at all times,

2. 62-302.500 - Surface waters: general criteria,

3. 62-302.400 - Class III Waters - Recreation, Propagation and maintenance of a healthy, well balanced population of Fish and Wildlife, and

4. 62-302.530(70) - Turbidity shall not exceed 29 Nephelometric Turbidity Units above background.

J. Dredging and filling in association with the installation of the natural gas <u>or water</u> pipeline<u>s</u> shall be limited that only that necessary to install the pipeline.

1. All disturbed areas shall be restored to their pre-existing ground surface conditions and elevations.

2. Construction techniques necessary for the installation of the gas pipeline, including transport and placement of material shall not disturb adjacent wetlands or surface waters and shall not adversely affect water quality.

3. During construction and while conducting normal maintenance activities, the applicant/licensee shall eradicate all Brazilian pepper, Australian pine and Melaleuca trees from the wetland portions of the right-of-way.

K. The applicants shall diligently and in good faith pursue an agreement with Orange County to obtain surface water from the adjacent Orange County Landfill property for use at the Stanton Energy Center Facility. The route for any necessary pipeline shall avoid and minimize wetland and surface water impacts to the extent practicable. The proposed construction and clearing shall be coordinated with the DEP in accordance with Condition V and shall be conducted in a manner that does not adversely affect threatened or endangered species.

L. The surface water management system for Unit<u>s</u> A <u>and B</u> will consist of modifications to an existing wet detention system. The control structure will be modified <u>as necessary to meet final design calculations for Unit B submitted pursuant to Condition VII.N below or otherwise</u> to incorporate a 5" circular orifice with an invert of 75.20 feet NGVD and a rectangular weir with invert elevation of 76.80 feet NGVD.

M. Before any offsite discharge from the stormwater management system occurs, the detention storage must be excavated to rough grade prior to building construction or placement of impervious surface within the area served by those systems.

1. Adequate measures must be taken to prevent siltation of these treatment systems and control structures during construction or siltation must be removed prior to final grading and stabilization.

2. The location of at least one bench mark (and it corresponding elevation) per stormwater pond should be placed in the vicinity of each inlet or outlet structure and will be clearly shown on the as-built plans provided to the Department.

N. Integrated Gasification Combined Cycle Unit B

1. At least ninety days prior to the commencement of construction, provide all information necessary for a complete Environmental Resource Permit application including the engineering drawings and supporting documentation necessary to demonstrate that the stormwater runoff from the proposed project will be treated and attenuated in accordance with Rules 40C-4, 40C-41 and 40C-42, F.A.C. The drawings and documentation shall be signed, sealed and dated by a professional engineer registered in the State of Florida.

2. Prior to the commencement of construction, the Department shall conduct a timely review of the submitted information and request the correction of any errors and omissions and any additional information necessary to complete the application. This shall be done in accordance with timeframes established in Chapter 120.60, F.S. and Rule 62-4.055, F.A.C.

3. The Department shall notify the licensee in writing that the application is complete upon review of all requested information and the correction of any errors or omissions. Construction shall not begin until the Department has provided such written notification.

VIII. ELECTRIC AND MAGNETIC FIELDS

The associated transmission lines shall comply with the requirements of Ch. 62-814, F.A.C.

IX. COOLING TOWER

A. Makeup Water Constituency

The CHSEC shall utilize treated sewage effluent, treated wastewater, onsite re-use water, landfill stormwater/leachate, stormwater runoff, or direct precipitation to the makeup water supply storage pond, as cooling tower makeup water. The effluent shall have received prior to use in the tower sufficient treatment from the source of cooling water, "a sewage treatment plant", but as a minimum, secondary treatment, as well as treatment described in Condition IX.B. below. Use of waters other than treated sewage effluent, or storm water, i.e., higher quality potable waters, or lower quality less-than-secondarily-treated sewage effluent, will require a modification of conditions pursuant to condition IV.N.3.

B. Chlorination

Treated sewage effluent used as cooling water makeup shall be treated to maintain a 1.0 mg/liter free chlorine residual for a 15 minute contact time, or alternately a demonstration that a viral concentration of less than one PFU per 25 gallons can be achieved at lower levels of chlorination. Chlorine levels shall be monitored continuously at the sewage treatment plants.

C. Special Studies

Upon satisfactory demonstration to the Department that the number of viruses entering the towers in the effluent makeup can be reduced to an undetectable level with the use of a lesser amount of chlorination or alternative treatment, the above requirement may be altered. This demonstration may occur through performance of special studies approved by the Department. Alteration of the chlorination requirements must still insure adequate treatment for the control of bacteria or viruses in the cooling water.

X. WATER DISCHARGES

A. Surface Waters

Any discharges from the site storage ponds or wastewater treatment system via any emergency overflow structure which result from any event LESS than a 25 year, 24 hour storm (as defined by the U.S. Weather Bureau Technical Paper No. 40, or the DOT drainage manual, or similar documents) shall meet State Water Quality Standards, Chapter 62-302, F.A.C.

B. Compliance

Any discharges into any Waters of the State during construction and operation of CHSEC Unit 1 shall be in accordance with all applicable provisions of Chapter 62-302, F.A.C., and 40 CFR, Part 423, *Effluent Guidelines and Standards for Stream Electric Power Generating Point Source Category*, except as provided herein.

C. Plant Effluents and Receiving Body of Water

For discharges made from the power plant the following conditions shall apply:

1. Receiving Body of Water (RBW)

The receiving body of water has been determined by the Department to be those waters of the Hart Branch, Cowpen Branch, or any other waters affected which are considered to be waters of the State within the definition of Chapter 403, Florida Statutes.

2. Point of Discharge (P.O.D.)

The point of discharge has been determined by the Department to be where the effluent physically enters the waters of the State in Hart Branch or Cowpen Branch.

3. Chemical Wastes

All discharges of low volume wastes (demineralizer, regeneration, floor drainage, lab drains, FGD blowdown and similar wastes) and metal cleaning wastes shall comply with Chapter 62-302. If violations of Chapter 62-302 occur, corrective action shall be taken. These wastewater shall be directed to an adequately sized and constructed treatment and detention facility.

During periods when treated wastewater does not comply with pH discharge limitations, the treated wastewater may be recycled to the recycle basin, except when the recycle pond has insufficient capacity to retain the recycled wastewater and the runoff from a rainfall event equal to or less than a 25 year-24 hour storm.

4. Coal Pile

Coal pile runoff shall be directed to the recycle basin and shall not be directly discharged to surface waters, except that discharge of stormwater runoff from the coal pile is allowed only during periods of high rainfall in excess of the 25 year-24 hour storm.

5. pH

The pH of the combined discharges shall be such that the pH will fall within the range of 6.0 to 9.0.

6. Polychlorinated Biphenyl Compounds

There shall be no net discharge of polychlorinated biphenyl compounds.

7. Metal Cleaning and Bottom Ash Sluice System Blowdown

Blowdown from the metal cleaning wastes and from the bottom ash sluice system shall be treated as appropriate prior to reuse and retention.

8. Solid Waste and Limestone Storage Areas

There shall be no direct discharge of stormwater runoff to surface waters from the solid waste and limestone storage areas prior to treatment.

9. Storm Water Runoff

During plant operation, necessary measures shall be used to settle, filter, treat or absorb silt-containing or pollutant-laden stormwater runoff to limit the suspended solids to 50mg/1 or less at the POD during rainfall periods less than the 25 year, 24 hour rainfall, and to prevent an increase in turbidity of more than 29 Nephelometric Turbidity Units above background in waters of the State.

Control measures shall consist at the minimum of filters, sediment traps, barriers, berms or vegetative planting. Exposed or disturbed soil shall be protected as soon as possible to minimize silt- and sediment-laden runoff. The pH shall be kept within the range of 6.0 to 8.5 at the POD.

D. Water Monitoring Program

The licensee shall monitor and report to the Department the listed parameters on the basis specified herein. The methods and procedures utilized shall receive written approval by the Department. The monitoring program may be reviewed annually by the Department, and a determination may be made as to the necessity and extent of continuation, and may be modified in accordance with Condition No. 1V.N.

1. Chemical Monitoring

The following parameters shall be monitored during operation as shown, commencing with the start of commercial operation of CHSEC and reported quarterly to the Department's Central District Office:

Parameter	Location	Sample Type	Frequency
Flow, groundwater	Wellfield Pipeline	Pump Logs	Continuous
Flow, Cooling Water Makeup	Intake	Pump Logs	Daily
TSS	Sewage and Treatment Facility	8 Hour Composite	Monthly
Chlorine	CHSES Sewage Treatment Plant	Grab	Weekly

The following parameters shall be monitored quarterly at any on-site generated wastewater discharge pipe into the makeup water storage supply pond and reported using the DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT form or monitored in appropriate groundwater monitoring wells.

Arsenic
Barium
Cadmium
Chromium
Fluorides
Lead
Mercury
Methoxychlor
Nitrate
Chlordane
bis- (2-Chloroethyl)- ether
1,2 diphenylhydraxine
Dichloromethane
Tetrachloroethylene
1,2 dichloroethane

Radioactive Substances:
  Gross Alpha
  Combined Ra^{226} and Ra^{228}
Selenium
Silver
2,4,-D
2,4,5,-TP
Toxaphene
Benzene
1, 1 dichloroethylene
1,1,1 trichloroethane
Vinyl Chloride
Trichloroethylene
Chloroform

2. Groundwater Monitoring

The groundwater levels shall be monitored continuously at selected wells as approved by the Department and the St. Johns River Water Management District. Chemical analyses shall be made on samples from all monitored wells identified in Condition XI.E. below. The location, frequency, and selected chemical analyses shall be given in condition XI.E.

The groundwater monitoring program shall be implemented at least one year prior to operation of CHSEC Unit 1 and shall be in conformance to DEP Rules 62-520 and 62-522, F.A.C. The chemical analyses shall be in accord with the latest edition of *Standards Methods for the Analysis of Water and Wastewater*. The data shall be submitted within 30 days of collection/ analysis to the St. Johns River Water Management District, and the DEP Central District Office.

Conductivity shall be monitored in wells around all lined solid waste disposal sites, coal piles, and wastewater treatment and sedimentation ponds.

3. Surface Water Monitoring

The surface waters leaving the CHSEC shall be monitored monthly when flowing at on site locations as approved by the Department, the St. Johns River Water Management District and the Orange County Pollution Control Department. The locations shall include Hart Branch and Cowpen Branch which may contain leachate, surface drainage or other surface water discharges.

The surface water monitoring programs shall be implemented at least one year prior to operation of CHSEC Unit 1. Monthly data shall be submitted within 30 days of collection/analysis to the Department, the St. Johns River Water Management District and the Orange County Environmental Protection Department. The chemical analyses shall be in accord with the latest edition of *Standards Methods for the Analysis of Water and Wastewater* and shall include at least the following chemical water quality parameters.

Conductance
pH
Sulfate
Nitrate
Chloride
Turbidity
Phosphorous
Iron

XI. GROUNDWATER

A. General

The use of groundwater from the wellfield for plant service water for CHSEC shall be minimized to the greatest extent practicable, but in no case shall withdrawals exceed 2.00 million gallons per day from the Floridan aquifer, nor shall maximum annual withdrawals exceed 321.20 million gallons.

B. Pump Test Program and Well Field Construction

60 days prior to construction of the wellfield the applicant shall submit final wellfield construction plans to the SJRWMD for approval. A pump test program shall be

performed to obtain aquifer parameters necessary for proper wellfield planning and construction. The proposed test program shall be submitted with the wellfield construction plans so that the SJRWMD in conjunction with the DEP can approve the adequacy of the program. The utilization of the test well as a production well is allowable provided the well is constructed to the standards provided in 40C-3, Part II, F.A.C.

Construction plans shall incorporate the appropriate aquifer parameters determined in the pump test program. The applicant shall submit all well logs and locate, design and construct all wells in accordance with 40C-3, F.A.C.

C. Water Use Restriction

Groundwater is restricted to uses other than cooling water make up. Any changes in the use of said water will require a modification of this condition.

D. Monitoring and Reporting

OUC shall, within the time limits hereinafter set forth, complete the following items.

1. The applicant shall install a flow meter for the production wellfield pipeline at the inlet to the plant service water pretreatment system. The applicant will maintain pump logs for operation of each production well in compliance with SJRWMD specifications. The pump logs will show the rating of each pump and record the length of time each pump is used. Well pumps will be calibrated on a yearly basis, and the calibration certificate shall be submitted to SJRWMD.

2. OUC shall submit to SJRWMD, on forms available from the District, a record of pumpage for each log used in D.1 above. Said pumpage shall provide on monthly basis, and shall be submitted by April 15, July 15, October 15 and January 15, for each preceding calendar quarter.

3. OUC shall maintain and operate a continuous water level; recorder on either the standby production well or a specially constructed observation well located at the Stanton site in Orange County, Florida. Detailed hydrographs of water level fluctuations shall be constructed with the data collected from the water level recorder and shall be submitted to SJRWMD by April 15, July 15, October 15, and January 15 for each preceding calendar quarter for the year prior to operation and the year after the initiation of operation. From the second year of operation on, water levels shall be reported twice a year (May and September).

4. Water quality analysis shall be performed on water withdrawn from each production wellfield pipeline at the inlet to the plant service water pretreatment

system. The water samples collected shall be collected after the well field has been pumping for at least 30 minutes. The water quality analysis shall be performed quarterly during the year prior to operation, monthly during the first year of operation, quarterly during the second year and twice each year (May and September) thereafter. Results shall be submitted to the SJRWMD within 45 days after such analyses were performed. If SJRWMD, DEP, or the applicant determines there is a significant change in water quality, then the applicant shall sample each individual well. The following parameters shall be analyzed:

Calcium	Magnesium	Sodium
Potassium	Bicarbonate	Sulfate
Chloride	Nitrate	Total Dissolved Solids
Hardness	Color	Total Phosphate
Gross Alpha	Fe, Ag, Cd, Zn, Cu, Ni, Se, Cr, As, Be, Hg, Pb, Mn, Al, Ba, Mo, V, Co, SO_3	
Specific Conductance		

All chemical analyses shall be performed in accordance with the latest edition of *Standard Methods for the Analysis of Water and Waste-Water*. The staff of the SJRWMD may adjust the parameters and intervals to be analyzed in accordance with hydrologic conditions determined by well logs and operating records.

5. In the event SJRWMD determines there is a sufficient change quality (substantially caused by CHSEC and causing a potentially significant effect on water use), the Department may propose pursuant to Section 403.516, F.S., that the licensee be required to reduce or cease withdrawal from these groundwater sources and/or that additional parameters be monitored.

E. Shallow Aquifer Monitoring Wells

After consultation with the DEP and SJRWMD, OUC shall install a monitoring well network to adequately monitor groundwater quality horizontally and vertically from the ground to the bottom of the Hawthorne Formation. Groundwater levels and flow directions will be determined twice a year (May and September) at the site through the preparation of seasonal piezometric contour maps. From these maps, the water quality monitoring well network will be located. Monitoring well locations and designs shall be submitted to the Department and SJRWMD for review and approval. Approval or disapproval of the locations and design shall be granted within 60 days. Monitoring wells of adequate design and number shall be installed up gradient and down gradient from each solid waste disposal area, each liquid waste pond and each coal pile storage area. An additional monitoring well will be placed immediately down gradient of the first section of each solid waste landfill to be utilized. The water samples collected from each of the monitor wells shall be collected immediately after removal by pumping of a quantity of water equal to two casing volumes. The water quality analyses shall be performed monthly during the year prior to commercial operation and quarterly thereafter. Results shall be submitted to the Department and the SJRWMD by the fifteenth (15th) day of the month following the month during which such analyses were performed. Testing for the following constituents is required:

TDS	Zinc
Conductance	Copper
PH	Nickel
Sulfate	Selenium
Color	Arsenic
Nitrate	Beryllium
Chloride	Mercury
Iron	Lead
Aluminum	Gross Alpha, Ra^{226} (when Gross-Alpha activity exceed 15 pCi/1
Cadmium	Total Phosphate
Silver	Calcium
Manganese	Magnesium
Barium	Potassium
Molybdenum	Sodium

Conductivity shall be monitored in wells around all lined ponds.

F. *Leachate*

1. Zone of Discharge

Leachate from the combustion waste landfills, coal storage piles, wastewater ponds, or storage ponds shall not contaminate waters of the State (including both surface and groundwater) in excess of the limitations of Chapter 62-302, or the Primary and Secondary Drinking Water parameters included in Chapter 62-550, F.A.C., beyond the boundary of separate and individual zones of discharge extending 50 feet below the ground surface and 100 feet from the edge of each individual pile or pond, except as provided in Condition XXII. The zone of discharge is defined in chapter 62-520., F.A.C.

2. Corrective Action

When the groundwater monitoring system shows a violation of the groundwater quality standards of Chapter 62-550, F.A.C., from this facility the appropriate ponds, combustion waste landfill, or coal pile shall be bottom sealed, relocated, fixed or the operation of the affected facility shall be altered in such a manner as to assure the Department that no violation of the groundwater standards will occur beyond the boundary of the zone of discharge. In addition, contaminated leachates shall be removed from ground waters.

G. Construction Dewatering Effluent

Construction dewatering effluent shall be treated when appropriate to limit surface water discharges of suspended solids to no more than 50 mg/l. The discharge of construction dewatering liquids shall not cause turbidity in excess of 29 Nephelometric Turbidity Units above ambient beyond a 20 meter radius from the point of discharge. Weekly grab samples will be collected and analyzed for suspended solids.

A program for controlling the groundwater impacts of construction dewatering shall be submitted to the Department and the SJRWMD for review and approval prior to implementation.

XII. SOLID WASTES

Solid wastes resulting from construction or operation shall be disposed of in accordance with the applicable regulations of Chapter 62-701, F.A.C. The licensee shall submit a program for approval outlining the methods to be used in handling and disposal of solid wastes. Such a program shall indicate at the least methods for erosion control, covering, vegetation, and quality control.

Open burning in connection with land clearing shall be in accordance with Chapters 62-256 and 5I-2, F.A.C. No additional permits shall be required, but the Orange County Pollution Control Department shall be notified prior to burning. Open burning shall not occur if the Division of Forestry has issued a ban on burning due to fire hazard conditions.

XIII. POTABLE WATER SUPPLY SYSTEM

The potable water supply system shall be designed and operated in conformance with Chapter 62-555, F.A.C. Information as required in 62-4 and 62-555, F.A.C. shall be submitted to the Department prior to construction and operation. The operator of the potable water supply system shall be certified in accordance with Chapters 62-555.35062-602.400, and 62-699, F.A.C.

XIV. TRANSFORMER AND ELECTRIC SWITCHING GEAR

The foundations for transformers, capacitors, and switching gear necessary to connect any CHSEC Unit to existing transmission and distribution system shall be constructed in such a manner as to allow complete collection and recovery of any spills or leakage of oily, toxic, or hazardous substances.

XV. CONSTRUCTION IN WATERS OF THE STATE

A. No construction on sovereign submerged lands shall commence without obtaining lease, easement or title from the Department and/or Trustees of the Internal Improvement Trust Fund.

B. Construction of pilings, railroad right-of-way, culverts, access roads, pipelines, and transmission towers shall be done in a manner to minimize turbidity. Turbidity screens should be used to prevent turbidity in excess of 29 NTU's above background beyond 40 meters from the excavation, right-of-way, pile driving, or construction site.

All spoil from construction of the CHSEC and related facilities shall be trucked to an upland disposal site of sufficient capacity to retain all material.

XVI. ALAFAYA TRAIL EXTENSION

A. Construction

1. The proposed Alafaya Trail Extension shall be routed as shown in Attachment A to these Conditions of Certification. Prior to construction of any of the projects referenced above, the licensee shall submit drawings on 8.5" by 11" paper, showing the final design, including plan views and cross-sections for each area of filling or clearing in wetlands. The drawings shall show the existing and proposed ground elevations and all existing and proposed structure location, sizes and invert elevations.

2. For the Alafaya Trail Extension, all work shall be confined to the road right-of-way (which term is deemed to include the stormwater ponds numbers 1 through 6 and the pond 4 outfall structure as shown in Attachment B to these Conditions of Certification and the combustion waste storage relocation area. Within 30 days of the completion of construction, the licensee shall arrange a site visit by DEP District personnel from the Central District office in Orlando to verify that no wetland damage has occurred outside the transmission line clear zone or the road right-of-way. If wetland damage occurs outside the transmission line clear zone or the road right-of-way during construction, the licensee shall submit to the Central District office in Orlando for review a plan to restore the wetland area which was damaged and to provide mitigation for the damage. The plan shall be implemented within 30 days of the Department approving the restoration and mitigation plan. This condition does not preclude the Department from taking enforcement action if unauthorized activities occur.

3. Prior to initiating construction, the licensee shall submit a map and aerial photographs showing the location of all staging areas for the Alafaya Trail Extension, transmission line and alternate access road construction to the Bureau of Wetland Resource Management for review and written approval. These areas shall be

upland areas which are not currently providing red-cockaded woodpecker nesting or foraging habitat. The staging areas shall not be used prior to receiving DEP approval.

4. The final two lanes of the proposed four-lane Alafaya Trail Extension are approved conceptually, although detailed plans for these two lanes must be submitted to the agencies for review pursuant to the conditions of certification. The conceptual approval is contingent on the road design being acceptable and acceptable mitigation being proposed to offset the impacts of the final two lanes. The mitigation for the final two lanes shall provide benefits for RCW habitat in east Orange County and RHPZ and wetland habitat of the Econlockhatchee River. The mitigation plan shall contain the information listed in Condition C of this section and shall be submitted to the Department, SJRWMD and the FFWCC for review. Construction of the final two lanes shall not be initiated until the road design and a mitigation plan has been approved.

B. Stormwater Management And Erosion Control For The Alafaya Trail Extension

1. For the portion of the Alafaya Trail Extension that parallels the railroad berm, drainage structures shall be placed under the road at the same location where drainage structures currently exist under the CSX Railroad berm. The drainage structures shall provide at least the same efficiency as the corresponding drainage structure currently existing in the CSX Railroad berm.

2. Within 30 days after completion of the stormwater management system, OUC must submit to the SJRWMD Form EN-45 (As Built Certification By a Registered Professional), signed and sealed by an appropriate professional registered in the State of Florida, and two sets of "As Built" drawings if: (a) the professional uses "As Built" drawings to support the As Built Certification, or (b) the completed system substantially differs from permitted plans.

3. One year after completion of the stormwater management system, and every two years thereafter, OUC, its successors, or assigns shall submit inspection reports to the SJRWMD on SJRWMD Form EN-46. The inspection form must be signed and sealed by an appropriate, registered professional.

4. All wetland areas or water bodies that are outside of the specific limits of construction authorized by this certification must be protected from erosion, siltation, scouring or excess turbidity, and dewatering.

5. OUC must construct and maintain a permanent protective vegetative and/or artificial cover for erosion and sediment control on all land surfaces exposed or disturbed by construction or alteration of the certified project. This protective cover must be installed within fourteen (14) days after final grading of the affected land surfaces. A permanent vegetative cover must be established within 60 days after planting or installation. OUC must maintain cover on adjacent ground

surfaces which may be impacted by construction activities until the SJRWMD receives the P.E. certification that the project is constructed according to the permitted plans.

6. Prior to beginning construction, OUC shall submit to the SJRWMD plans, data analyses, and other similar information demonstrating that the construction of the roadway and associated stormwater management facilities meet SJRWMD's criteria and requirements with regard to water quality and water quantity impacts.

C. Mitigation Criteria For The Alafaya Trail Extension

1. The proposed mitigation plan submitted to SJRWMD by OUC for the Curtis H. Stanton Energy Center, Unit 2, dated June 21, 1991, July 20, 1991, September 11, 1991, September 18, 1991, and September 19, 1991 and the proposed mitigation plan submitted to SJRWMD for the Alafaya Trail Extension dated October 5, 1992, and subsequently modified on May 5, 1993, which is attached hereto, are incorporated as a condition of this certification except where specifically superseded by certification conditions.

2. Mitigation for the impacts of the first two lanes of the proposed four-lane road shall be accomplished through the implementation of one of the following two options:

a. The 37.31 ac. wetland creation and upland enhancement plan proposed in the original October 5, 1992, Request to Modify the certification and subsequently modified in a May 5, 1993, submittal to SJRWMD, which is attached hereto.

b. Upon approval by ACOE, USFWS, EPA, and SJRWMD the 37.31 ac. mitigation area shall be placed under a conservation easement to the Department and $430,000 shall be contributed toward the purchase of lands deemed acceptable for mitigation by SJRWMD with an effort towards locating such mitigation parcel(s) within Orange County, if feasible. The land purchased with the money would be conveyed to SJRWMD. This option may be exercised up to 30 days prior to the commencement of construction of the roadway.

3. If mitigation is performed pursuant to the proposed 37.31 acre wetland creation and adjacent upland enhancement plan submitted to SJRWMD for the Alafaya Trail Extension dated October 5, 1992, and subsequently modified on May 5, 1993, which is attached hereto, the following conditions shall apply to these areas:

4. OUC must submit to the Department and SJRWMD two copies of an as-built survey of the wetland creation and upland enhancement areas certified by a registered surveyor or professional engineer showing dimension, grades, ground

elevations, and water surface elevations. This as-built survey must be submitted with the first monitoring report.

5. Within the wetland creation areas, non-native vegetation, cattails (*Typha* spp.) and primrose willow (*Ludwigia peruviana*), must be controlled by hand clearing or other methods approved in writing by the Department and SJRWMD so that they constitute no more than 10% of the areal cover in each stratum at any time.

6. The wetland creation and upland enhancement areas must be planted prior to use of the infrastructure for its intended purpose.

7. Within 30 days of any monitoring event that indicates 50% or greater mortality of planted wetland and upland species in any stratum within the mitigation area, OUC must submit a remediation plan to the Department, SJRWMD and FFWCC for review. The plan shall not be implemented until written approval has been issued by the Siting Coordination Office.

8. OUC must furnish the Department, SJRWMD, and FFWCC two copies of monitoring reports for the wetland creation and upland enhancement area describing:

a. Percent survival and recorded growth via established parameters for planted trees and shrubs;

b. Percent cover for all species within each stratum;

c. Total percent cover of herbaceous species;

d. Ground and surface water monitoring data including:

(1) Surface water elevation referenced to N.G.V.D., or if surface water is not present, ground water elevation referenced to N.G.V.D.;

(2) Location of staff gauges and piezometers; and,

(3) Date and time of measurements.

e. Observations of wildlife utilizations;

f. Panoramic photographs of the mitigation site taken from approved permanent stations;

g. A description of any problems encountered, including removal of any non-target species, replacement and maintenance dates, and solutions; and,

h. Any anticipated work for the successive six month period following each assessment.

The data must be collected and submitted semi-annually, once during the wet season (August - September) and once during the dry season (March - April) until the created and enhanced areas achieve the success criteria.

9. Successful establishment of the planted vegetation in the wetland creation and upland enhancement areas will have occurred when:

a. At least 80 percent of the planted individuals in each stratum have survived and are showing signs of normal annual growth for three consecutive years, based upon standard growth parameters such as height and base diameter, or canopy circumference;

b. At least 80 percent cover by appropriate wetland herbaceous species in the wetland creation area has been obtained; and,

c. The above criteria have been achieved by the end of a five (5) year period following initial planting.

10. If successful establishment has not occurred as stated above, or is unlikely based upon the monitoring reports or trends, OUC must, within 30 days, submit a mitigation correction plan to the Department, SJRWMD, and FFWCC. The mitigation correction plan must include a narrative describing the type and causes of failure and contain a complete set of plans for the redesign and/or replacement planting of the wetland creation or upland enhancement areas so that success criteria will be achieved. Within 30 days of approval of the mitigation correction plan by the Siting Coordination Office, OUC must implement the redesign and/or the replacement planting. Following completion of such work, success criteria as stated above or as modified by the mitigation correction plan must again be achieved. In addition, the monitoring required by these certification conditions must be conducted.

11. OUC must plant herbaceous wetland species, approved by the Department and SJRWMD, to supplement ground cover, if natural recruitment of desirable species does not occur in the cover stratum of the wetland creation area. If planted, such species must achieve 80 percent coverage after a three year period.

12. Irrigation and fertilization of the wetland creation or upland enhancement areas may occur in the first year after initial planting in accordance with Rule 40C-21, F.A.C.

13. The use of non-native grasses, or the placement of sod, in the wetland creation or upland enhancement areas is specifically prohibited.

14. Within 30 days of completion of initial planting, OUC must submit to the Department, SJRWMD, and FFWCC for review and approval a plan detailing the site-specific methods to be used for monitoring the wetland creation and upland enhancement areas so that achievement of success criteria can be clearly demonstrated. The plan must include such information as the size, location, and number of monitoring quadrants, the location and number of photographic stations, and other pertinent factors to demonstrate achievement of success criteria.

15. Prior to initiating any construction, OUC must record a conservation easement in favor of the Department and SJRWMD over the wetland creation and upland enhancement areas prohibiting all construction, including clearing, dredging, or filling, except that which is specifically authorized by this certification. The easement must contain provisions as set forth in paragraphs 1(a) - (h) of section 704.06, F.S.

16. Within 30 days of the date of issuance of this certification and prior to recording, the conservation easement language must be submitted to the Department, SJRWMD, and FFWCC for approval. The easement shall not be recorded until the proposed language has been approved in writing by the Siting Coordination Office.

17. Within 30 days of receipt of the Siting Coordination Office's approval, OUC must provide the Department with the original recorded conservation easement and provide copies of the same to SJRWMD and FFWCC. The copies of the recorded easement must show the date the conservation easement was recorded and the official records book and page number.

18. Legal access, at least 15 feet in width, must be provided to the wetland creation and upland enhancement areas for the Department and SJRWMD staff and equipment.

XVII. SOLID WASTE LANDFILL

A. The proposed solid waste landfill area shall be monitored and studied pursuant to an adequately detailed groundwater testing and monitoring program as defined in Condition IV, D. and E. The results of this detailed groundwater testing and monitoring program will be used by the Department in determining whether OUC shall affirmatively demonstrate that Florida Water Criteria (Chapter 62-550, F.A.C.) will not be violated.

B. Before construction of the solid waste landfill or any expansion thereof commences, Karst features interfering with the hydrogeological integrity of the site in the vicinity of the solid waste landfill shall be adequately stabilized both physically and hydraulically against, respectively, collapse and unusual downward transport of groundwater.

C. OUC shall select and adopt one or more of the following mitigative measures for controlling water quality beneath the solid waste landfill:

1. Use of an adequate chemical fixation process on the solid wastes to achieve a uniform layer at least 18 inches in thickness across the cell with a permeability of 1×10^{-7}cm/sec or less.

2. Use of an adequate chemical fixation process on the solid wastes to achieve solid waste permeability of 5×10^{-6}cm/sec or less. The top of each completed cell shall be constructed with a slope of 0.75% and an effort will be made to decrease the permeability of the top layer of fixed FGD material to less than 5×10^{-6} cm/sec.

D. Ninety days prior to operation of Unit 1, OUC shall submit a program demonstrating how the fixed FGD waste landfill permeability will be maintained at or below a level of 5×10^{-6}cm/sec. The DEP will indicate its approval or disapproval of the program within 60 days. OUC shall implement an approved program.

E. OUC shall adopt in addition all of the following mitigative measures for further controlling water quality beneath the solid waste landfill:

1. Use of adequate ramp-slopes over combustion waste storage cells and an adequate perimeter toe ditch and interceptor ditch system for controlling and concentrating rain runoff within the solid waste landfill area.

2. Use of adequate and systematic measures for compacting all solid wastes as they are emplaced within the landfill.

3. Maintenance of a soil cover and a viable community of grasses, which would eventually extend over the entire solid waste landfill area.

F. Prior to the commencement of operation of solid waste disposal areas or expansion thereof, the following shall be submitted to the Department and the St. Johns River District Manager for review and approval consistent with other conditions of this certification:

1. Plot Plan - should be drawn on a scale not greater than 200 ft. to the inch showing the following:

a. Dimensions and legal description of the site

b. Location and depth corrected to MSL of soil borings

c. Proposed trenching plan

d. Cover stockpiles

e. Fencing or other measures to restrict access

f. Cross sections showing both original and proposed fill elevation

g. Location, depth corrected to MSL, and construction details of monitoring wells or ditch monitoring points

2. Design Drawings and Maps - may be combined with plot plan and should be drawn on a scale no greater than 200 ft. to the inch showing the following:

a. Topographic map with five foot contour intervals

b. Proposed fill areas

c. Borrow area

d. Access roads

e. Grades required for proper drainage

f. Typical cross sections of disposal site including lifts, borrow areas and drainage controls

g. Special drainage devices

3. Soil map, Interpretive Guide Sheets and a report giving the suitability of the site for such an operation.

4. Operation plans to direct and control the use of the site.

5. An indication by discussion or drawings or both of how the site is designed to meet water quality standards of Chapter 62-302 and 62-550, F.A.C, at the waste site boundary or the boundary of the zone of discharge. Adequate indications above would include discussion of each mitigative water quality control measure that would be employed, including but not limited to: liners, chemical fixation process, compaction, under drains and chemical treatment facilities, impermeable clay caps, soil and grass communities.

Based on the Department's reviews of the above, additions to or modifications of the overall monitoring program may be required for monitoring of runoff, groundwaters, and surface waters which may be affected by the various land filling operations.

The Department shall indicate its approval or disapproval of the submitted plans, drawings, maps, analyses and contingency plans within 60 days.

XVIII. TRANSMISSION LINES, ACCESS ROAD, NATURAL GAS PIPELINE AND RAIL SPUR

A. General

1. Filling and construction in water of the State shall be minimized to the extent practicable. No such activities shall take place without obtaining lease or title from the Department and/or TIITF where required. Construction and access roads should avoid wetlands and be located in surrounding uplands to the extent practicable.

2. Placement of fill in wetland areas shall be minimized by spanning such areas with the maximum span practicable. Borrow pits shall not be located in waters of the State.

3. The Department may determine that any fill required in wetlands for construction but not required for maintenance purpose shall be removed and the ground restored to its original contours after transmission line, roadway or rail spur placement. Placement and removal of any such temporary fill shall be coordinated with the DEP District Office.

4. Where fill in wetlands is necessary for access, keyhole fills from upland areas should be oriented as nearly parallel to surface water flow lines as possible.

5. Sufficient size and number of culverts or other structures shall be placed through fill causeways to maintain substantially unimpaired sheet flow.

6. Turbidity control measures, including but not limited to hay bales, turbidity curtains, sodding, mulching, and seeding, shall be employed to prevent violation of water quality standards.

7. The Rights-of-Way shall be located so as to minimize impacts in or on streambeds such as the removal of vegetation, to the extent practicable. For transmission lines, within 25 feet of the banks of any streams, rivers or lakes, vegetation shall be left undisturbed, except for selective topping of trees or removal of trees which topping would kill. For transmission lines, if it is necessary to remove such trees within 25 feet of the banks of streams, rivers or lakes, the root mat shall be left undisturbed.

8. Any necessary water quality certifications which must be made to the Corps of Engineers shall be made at the time of a finding of compliance for specific work at specific locations.

9. Construction activities should proceed as much as practicable

during the dry season.

B. *Other Construction Activities*

1. Maintenance roads under control of the licensee shall be planted with native species to prevent erosion and subsequent water quality degradation where drainage from such roads would impact waters of the State significantly.

2. Good environmental practices such as described in *Environmental Criteria for Electric Transmission Systems* as published by the U.S. Department of Interior and the U.S. Department of Agriculture shall be followed to the extent practicable.

3. Compliance with the most recent version of the National Electric Safety Code adopted by the Public Service Commission is required.

4. Fences running parallel to the transmission line which may become conductive shall be grounded at appropriate intervals; fences running perpendicular to the line shall be grounded at the edge of the right-of-way.

5. Field reconnaissance of rare and endangered species shall be performed in order to minimize impacts on these species.

6. Open burning in connection with land clearing shall be in accordance with the applicable rules of the Department of Agriculture and Consumer Services. No additional permits shall be required, but the Orange County Pollution Control Board shall be notified prior to burning. Open burning shall not occur if the Division of Forestry has issued a ban on burning due to fire hazard conditions.

C. *Maintenance*

1. Vegetative clearing operations for maintenance purposes to be carried out within the corridor shall follow the general standards for clearing right-of-way for overhead transmission lines as referenced in Sections XIV.A.7 and XIV.B.2. Selective clearing of vegetation is preferred over clearing and grubbing or clear cutting.

2. If chemicals or herbicides are to be used for vegetation control, the name, type, proposed use, locations, and manner of application shall be provided to the Department prior to their application for assessment of compliance with applicable regulations.

D. Archaeological Sites

Any archaeological sites discovered during construction of the transmission lines, access roads or rail spurs shall be disturbed as little as possible and such discovery shall be communicated to the Department of State, Division of Historical Resources (DHR). Potentially affected areas will be surveyed, and if a significant site is located, the site shall be avoided, protected, or excavated as directed by DHR.

E. Road Crossing

For all locations where the transmission line, the rail spur or gas pipeline will cross State highways, the applicant will submit materials pursuant to the Department of Transportation's (DOT) "Utility Accommodation Guide" to DOT's district office for review and approval. All applicable regulations pertaining to roadway crossings by rail or transmission lines shall be complied with. Crossing of county roads shall be coordinated with the County Engineer.

F. Emergency Reporting

Emergency replacement of previously constructed right-of-way or transmission lines shall not be considered a modification pursuant to Section 403.516, F.S. A verbal report of the emergency shall be made to the Department as soon as possible. Within fourteen (14) calendar days after correction of the emergency, a report to the Department shall be made outlining the details of the emergency and the steps taken for its temporary relief. The report shall be a written description of all of the work performed and shall set forth any pollution control measures or mitigative measures which were utilized or are being utilized to prevent pollution of waters, harm to sensitive areas or alteration of archaeological or historical resources.

G. Final Right-Of-Way Location

A map of 1:24000 scale showing final location of the right-of-way shall be submitted to the Department upon completion of acquisition.

H. Compliance

Construction and maintenance shall comply with the applicable rules and regulations of the Department and those agencies specified in 62-17.54(2)(a) and (b), F.A.C.

I. Construction Plans

All proposed transmission line ROW areas, plant access roads and railroad lines which are designed to traverse a stream, lake, pond, canal, swamp, marsh or other natural or artificial system which functions to store or convey water and would require a permit under Chapter 40C-4 or 40C-6, F.A.C., shall have said design plans and specifications reviewed by the SJRWMD or SFWMD staff. The staff shall determine if such plans are consistent with the Site Certification Application, the Recommended Conditions of Certification and applicable District rules. To determine such consistency, information to include but not be limited to the following items shall be submitted to the District 60 days prior to construction:

1. A centerline profile of existing topographic features along proposed access road (s).

2. Preliminary design of proposed access road (s) with elevations marked.

3. Typical cross-section of access road (s).

4. Cross-section of each stream of creek at those points to be crossed by access road (s) or other facilities.

5. Specifications showing size and type of water control structure (pipe, culvert, etc.) to be placed within or on waters of the District, with proposed flow-line elevations marked.

6. Specifications showing design capacity of all water control structures to be employed.

7. Specifications showing location and type of each transmission tower and access road (s) to be constructed within or on the waters of the District.

8. Computer rates of flow for streams or water courses before and after construction during a one hundred (100) year flood.

9. Any other information needed by OUC to show compliance with standards in Rule 40C-4 and 40C-6, Florida Administrative Code.

XIX. FLOOD CONTROL PROTECTION

The plant and associated facilities shall be constructed in such a manner as to comply with the Orange County flood protection requirements.

XX. RAILROAD SPUR LINE

Modifications to the railroad spur line proposal as presented in the Site Certification Application would require that the modifications be reviewed by the South Florida Water Management District's staff for concurrence, and approved by the Secretary.

XXI. RED COCKADED WOODPECKER

A. Implementation Of Red Cockaded Woodpecker Management Plan

The management plan for the Red-Cockaded Woodpecker, as described in XXI.D. below, shall be implemented for the life of the facility. The monitoring program shall be extended to cover the first five years of plant operation unless the Florida Fish and Wildlife Conservation Commission should recommend a termination of the monitoring program.

B. Red-Cockaded Woodpecker Management Area Identification

All lands depicted in the Red-Cockaded Woodpecker Management Plan, Figure 4-2, except for the area specifically identified as "construction impact of proposed generating Units 1, 2, 3, and 4" constitute the red-cockaded woodpecker management area subject to the Management Plan.

C. Use And Limitations Of The Red-Cockaded Woodpecker Management Area

With regard to the red-cockaded woodpecker management area, in addition to Condition XXI.B., above:

1. OUC may conduct activities within the red-cockaded woodpecker management area which are provided for in the Siting Board's certification orders for Units 1 and 2, including without limitation the execution of habitat restoration, enhancement, and creation required as mitigation.

2. OUC may conduct management, including maintenance in their existing configuration and condition, of existing unpaved private roads utilized by OUC, maintenance of existing water and sewer lines, of existing transmission lines and substation, and other maintenance and management activities which are consistent with its purposes, within the red-cockaded woodpecker management area.

3. OUC shall take appropriate action to manage the red-cockaded woodpecker management area to achieve the purposes required by Condition XXI.B., above, with regard to the red-cockaded woodpecker, and in general to preserve the natural conditions of the area, including other protected species of native wildlife, vegetation, wetlands, and particularly the tributaries and headwaters of the

Econlockhatchee River. OUC may act to implement the red-cockaded woodpecker management plan, to monitor its effectiveness, and to react to fire, flood, or other unforeseeable natural or manmade disturbances. Any reports generated by OUC concerning activities within or management of the red-cockaded woodpecker management area shall be provided to the Florida Game and Fresh Water Fish Commission.

4. OUC shall allow only those activities of others within the red-cockaded woodpecker management area which are consistent with its management in a natural state. Such activities shall be limited to environmental restoration, scientific research, habitat management (such as controlled burning) and nature study.

5. Unless specifically authorized by an order of the Siting Board, dredging, filling, construction of buildings, road-ways, dumping of debris, excavation, and clearing of native vegetation shall be prohibited in the area defined by Condition XXI.B., above. The provisions of Sections 403.516(1)(a) and (b), F.S., notwithstanding, OUC agrees that any activity prohibited in this paragraph within the area described in the red-cockaded woodpecker management area shall be authorized only by affirmative vote of the Siting Board.

6. OUC hereby stipulates as a factual matter, which shall be binding on it, and all of its officers, agents, attorneys, and employees, that the "alternate access road" authorized by this supplemental certification completes the necessary roadway access for Units 1 and 2, to allow the full development thereof. Any additional access for electric power generation, and any additional facilities necessary for the construction of Units 3 and 4 will be the subject of a comprehensive Supplemental Certification Application or applications for Units 3 and 4.

7. If OUC determines to pursue a modification of its certification with regard to the easement recorded December 30, 1987, at ORB 3946, Page 3187, Orange County, Florida, it shall do so as a ministerial act only and shall not actively utilize its resources, funds or personnel to support such an application.

D. Management Plan For The Red-Cockaded Woodpecker (Originally Published June 29, 1981)

1. Introduction

A management and monitoring plan will be adopted to ensure long-term presence of red-cockaded woodpeckers on the OUC Stanton site. The following description relates recommended procedures for the proposed management plan. The major emphasis of this plan is protection of existing colonies and provision for adequate foraging range.

For details of the study which is the basis for this management plan, see Attachment 5.7A of the Site Certification Application for OUC Unit 1, dated 1981.

Approximately 2,000 acres will be managed for the benefit of the red-cockaded woodpecker. This acreage will include both existing colonies and approximately 222 acres of foraging habitat for each on-site clan. Within the managed area, there are 1,753 acres of pine flatwoods, 217 acres of cypress dome, and 29 acres of wet prairie.

The mean basal area in pine flatwoods for the entire site is approximately 10 ft^2/acre. The United States Fish and Wildlife Service (1979) recommends that a basal area of 40 to 60 ft^2/acre and a stem density of less than 200 stems per acre represent better quality foraging habitat for red-cockaded woodpeckers. Because of relatively unproductive soils and other factors, it may not be possible to attain these conditions on the Stanton site. However, with a proper timber management plan, the basal area and stem density for on-site flatwoods could be substantially increased during the next 20 to 30 years. In addition, cypress domes apparently constitute an important feeding site for on-site red-cockaded woodpeckers, particularly during the fall. These forests are greatly stressed by frequent muck fires. With a better controlled fire program, these detrimental effects could be substantially reduced.

2. Recommendations

To meet the above-stated goals, the following procedures are recommended:

a. Maintain all remaining cavity trees (active and inactive);

b. Protect colony sites, including surrounding trees, to ensure future replacement cavity trees and to serve as a buffer zone;

c. Construct two artificial start holes for each cavity tree removed during construction activities;

d. Thin colony sites for habitat management purposes only;

e. Maintain other potential stands for future colony sites;

f. Manage approximately 2,000 acres of foraging habitat for on-site clans;

g. Conduct a regular, prescribed burning program;

h. Provide contiguous habitat between colonies and foraging habitat and between adjoining clans;

i. Prohibit indiscriminate logging and other detrimental disturbances in exclusive areas to be managed for red-cockaded woodpeckers;

j. Allow all previously disturbed areas (pre-construction activities) within the managed area to reseed naturally with longleaf pine; and,

k. Conduct on-site monitoring of territorial behavior of clans during pre-construction and construction phases of the proposed power plant.

Any variation in the above procedures must be approved by a qualified biologist.

3. Implementation

The following schedule is proposed to implement the procedures recommended in Condition XXI.D.2.:

a. Construction contractors will be briefed as required on their legal obligations under the Endangered Species Act and regulations of the Florida Fish and Wildlife Conservation Commission. This briefing will include information and limits of construction activities which meet compliance with stated impacts described in this document. Construction activities will be monitored by Orlando Utilities Commission. Construction activities are described in the Site Certification Application (SCA) for the State of Florida. The area disturbed by the proposed action will be consistent with the area displayed in Figure 4-2, attached.

b. All colony areas and buffer zones will be conspicuously marked prior to construction. Endangered species posters will be attached to active cavity trees. Potential replacement cavity trees and younger pines within each colony area will be retained. No harvesting of pines will be scheduled for colony areas except for habitat management purposes. A 200-foot buffer zone will be established around each active cavity tree during construction activities. Currently all cavity trees are located in open stands of pines with relatively few second-growth pines or hardwoods. Thus, there should be no immediate need for stand improvements (thinning) in colony sites. Attempts should be made, however, to promote a basal area of 50 to 80 ft^2/acre in colony trees. Abandoned cavity trees and dead snags in the managed area will not be disturbed to provide roosting and nesting sites foe competitive species.

c. Prescribed burns should be conducted on a regular basis in both colony sites and foraging habitat. Prior to prescribed burns, a 6-foot buffer zone around each cavity tree should be cleared of excess resin, litter, and other debris. Burns should be scheduled from August to February so as not to interfere with the nesting season (March through July). Local foresters should be consulted on the time of year and weather conditions appropriate for burning. During normal fire schedule, prescribed burns should be conducted on a 2- to 3-year rotation. Burns will be controlled in order to prevent extensive muck fires in cypress domes and to preclude hot burns in pine flatwoods.

It is recommended that no more than one-half of the 2,000 acres be burned during any yearly cycle. Within this yearly burn cycle, it is advisable to burn approximately one-fourth of the site during the October/November period with the remaining portion to be burned during the January/February period.

Production of seedling pines is low in many stands on the Stanton site. To stimulate pine regeneration, a fire suppression period should be scheduled for at least 4 years. The fire suppression period should be initiated following a year of peak cone production in on-site flatwoods. However, during this peak production year, a burning cycle should be completed by late August. Subsequently, the suppression period would follow for the next 4 years. Following this period, the fire schedule should be conducted on the normal 2- to 3-year rotation.

Many of these recommendations were obtained from the Florida District Forest Ranger. It is recommended that he/she be consulted on the appropriate sequence of the previously stated fire schedule.

d. No unapproved timber harvesting within the managed area will be scheduled. Stands of pine will be allowed to mature and die. The United States Fish and Wildlife Service (1979) recommends a 50-percent balance between older age classes and younger stands of pines. As previously stated, the burning program will be manipulated in order to stimulate natural regeneration. This action will produce better quality foraging habitat and a more even distribution of age classes.

e. Pesticides toxic to wildlife will not be used in any part of the clans' home ranges.

f. Potential colony sites have been mapped. These potential sites within the managed area will be protected from future development. Burning and rotation should follow procedures outlined for present colony sites.

g. Monitoring studies will be conducted during the pre-construction and construction phases of the proposed action. Monitoring activities will consist of collecting baseline data for 1 year, including evaluation of home range and reproductive success. Range data will be collected for a minimum of 140 hours per clan. Reproductive success will be evaluated during two nesting seasons.

Construction monitoring will include evaluation of home range and reproductive success. The evaluation of home range will be conducted during the first and third years of the construction phase. The third year of monitoring will include the initial period of plant operation. Monitoring for range data purposes will consist of 140 hours of observation per clan during the construction phase. Reproductive success will be evaluated during each year of construction. The major activity affecting red-cockaded woodpeckers (land clearing) will occur during the first year of construction. However, the peak of construction activities will occur during the third year.

Clans A, B, C, D, and H have been selected for home range study. The first four clans will receive the greater impacts from the proposed action. No habitat alteration will occur in Clan H's home range; therefore, any impacts would reflect only indirect influence from the proposed action. Reproduction will be monitored for all on-site clans. In the event that monitored colonies are deserted, surrounding areas on the site, as well as some adjoining lands, will be surveyed. A number of areas apparently suitable for red-cockaded woodpeckers, but which did not contain colonies, have been located. These areas would be surveyed.

XXII. NITRATE

OUC shall monitor nitrate levels in Hart Branch at the site boundary during construction to establish background levels of that parameter. Monitoring of nitrate shall continue during plant operation. If nitrate levels exceed 1.0 mg/l or if preoperational background levels of NO_3 exceed 1.0 mg/l and plant operation causes the NO_3 levels to rise more than 25% above background, OUC shall take appropriate action to control the NO_3. Nitrate and other contaminants from the water supply pond will be monitored at incremental distances from the pond in a program to be submitted by OUC and approved by the DEP and SJRWMD to determine the dispersion and diluting characteristics of nitrate in the non-artesian groundwater aquifer. Based on the results of the monitoring, a projection of nitrate concentration at 500 feet from the pond will be made. If these projections indicate that at 500 feet from the pond the ground water nitrate concentrations will be at or above 10 mg/l, then OUC will develop a program of corrective action. Such corrective action will be prepared by OUC and implemented after approval of the DEP, SJRWMD, and Orange County. Other contaminants shall be allowed a zone of discharge 50 feet deep extending 250 feet from the pond.

XXIII. FISH AND WILDLIFE MANAGEMENT

OUC shall consult with the Florida Fish and Wildlife Conservation Commission and, if possible, implement a fish and wildlife management plan as discussed in the Commission's letter of February 12, 1982.

XXIV. COAL PILE

The coal pile shall be lined with a material with a permeability not greater than 1×10^{-7} cm/sec. or the leachate shall be controlled to prevent violation of water quality criteria beyond the zone of discharge.

XXV. FISH AND WILDLIFE CONSERVATION COMMISSION

A. Wildlife Survey

Prior to the construction of the proposed facility, a wildlife survey, consistent with methodology prescribed by the FFWCC, shall be conducted for the presence of listed species (endangered, threatened, or species concern) and suitable habitat for same within the site. The results of said survey shall be submitted to the DEP, the FFWCC, and the United States Fish and Wildlife Service. If construction of the proposed facility will impact any listed species, other than the previously identified impact on the foraging habitat of the red-cockaded woodpecker resulting from the clearing of the transmission line right-of-way, the Licensee shall consult with the DEP and the FFWCC to determine the appropriate steps to avoid, minimize, mitigate, or otherwise appropriately address any adverse impacts within each agency's respective jurisdiction.

B. Nesting Sandhill Cranes

Nesting sandhill cranes shall be avoided by limiting installation of transmission lines over wetlands utilized by nesting cranes to periods outside of the nesting season, which runs from January through June.

C. Management Plan

Before construction, a management plan for the preserved areas shall be presented to the FFWCC for review and approval. At a minimum, this plan shall include a statement of what habitat function the preserve is expected to provide; a schedule of fire management through a certified burn specialist and including, but not limited to, burn conditions, burn frequency, and measures taken to avoid spread of wildfire; measures taken to remove exotic vegetation from both wetlands and uplands; and the responsible entity.

D. Natural Gas Pipeline

In order to minimize impacts to the red-cockaded woodpecker, we recommend that the construction of the natural gas pipeline in the vicinity of the red-cockaded woodpecker cavity trees occur outside the nesting season (April through June), or a determination be made by a qualified biologist that nesting is not occurring in any cavity tree within 200 feet of the edge of the construction right-of-way prior to initiation of pipeline construction activities.

XXVI. SOUTH FLORIDA WATER MANAGEMENT DISTRICT – LEGAL & ADMINISTRATIVE CONDITIONS

A. General

1. Compliance Requirements

This project must be constructed, operated and maintained in compliance with and meet all non-procedural requirements set forth in Chapter 373, F.S., and Chapter 40E-4 (Surface Water Management), F.A.C.

2. Off-Site Impacts

It is the responsibility of the Licensee to ensure based on information provided that adverse off-site water resource related impacts do not occur during the construction, operation, and maintenance of the transmission line and associated transmission line access roads within SFWMD.

3. Post Certification Information Submittals

Information submitted to the SFWMD subsequent to Certification, in compliance with the conditions of this Certification, shall be for the purpose of the SFWMD determining the Licensee's compliance with the Certification conditions and the non-procedural criteria contained in Chapter 40E-4, F.A.C., as applicable, prior to the commencement of the subject construction, operation and/or maintenance activity covered thereunder.

B. Processing Of Information Requests

1. Right-of-way Modifications

At least ninety (90) days prior to the commencement of construction of any portion of the transmission line, the Licensee shall submit any proposed modifications to the transmission line right-of-way, identified on Exhibits 2, 3 and 4 (Figures 6.1-2, 6.1-3, and 6.1-4), to the SFWMD staff for review and approval. If the SFWMD staff does not issue a written request for additional information and/or an objection to the proposed right-of-way modification within thirty (30) days, the modification shall be presumed to be complete and acceptable.

2. Completeness and Review

At least ninety (90) days prior to the commencement of construction of any portion of the linear facilities located in the SFWMD, the Licensee shall submit to SFWMD staff, for a completeness and sufficiency review, any pertinent additional information required under the SFWMD's Conditions of Certification for that portion proposed for construction. If SFWMD staff does not issue a written request for additional information within thirty (30) days, the information shall be presumed to be complete and sufficient.

3. Compliance Review and Confirmation

Within sixty (60) days of the determination by SFWMD staff that the submitted information is complete and sufficient, the SFWMD shall determine and notify the Licensee in writing whether the proposed activities conform to SFWMD criteria, as required by Chapter 40E-4, F.A.C., and the Conditions of Certification. If necessary, the SFWMD shall identify what items remain to be addressed. No construction activities shall begin until the SFWMD has determined either in writing, or by failure to notify the Licensee in writing, that the activities are in compliance with the applicable SFWMD criteria.

4. Revisions to Site Specific Design Authorizations

The Licensee shall submit, consistent with the provisions of Condition IV/I.B, any proposed revisions to the site specific design authorizations specified in this Certification to the SFWMD for review and approval prior to implementation. The submittal shall include all the information necessary to support the proposed request, including detailed drawings, topographic maps, average wet season water table elevations, calculations and/or any other applicable data. Such requests may be included as part of the appropriate additional information submittals required by this Certification provided they are clearly identified as a requested modification to the previously authorized design.

5. Dispute Resolution

Since this Certification is the only form of permit required from any agency, it is understood that the Licensee and the SFWMD shall strive to resolve disputes by mutual agreement.

6. Objections

Objections to modifications of the terms and conditions of this

Certification shall be resolve through the process established in Section 403.516, F.S.

7. Changes to Information Requirements

The SFWMD and the Licensee may jointly agree to vary the informational requirements.

XXVII. SFWMD SURFACE WATER MANAGEMENT CONDITIONS

A. General Conditions

1. Professional Engineer Certificate

The operation of the surface water management system authorized under this certification shall not become effective until a Florida Registered Professional Engineer certifies, upon completion of each phase, that these facilities have been constructed in accordance with the design approved by the SFWMD. Within 30 days after completion of construction of the surface water management system, the Licensee or authorized agent shall submit the engineer's certification and notify the SFWMD Field Engineering Division that the facilities are ready for inspection and approval. Such notification shall include as-built drawings of the site which shall include elevations, locations, and dimensions of components of the surface water management system.

2. Impacts of Fish, Wildlife, Natural Environment Values and Water Quality

The Licensee shall prosecute the work authorized under this Certification in a manner so as to minimize any adverse impacts of the authorized works on fish, wildlife, natural environment values, and water quality. The Licensee shall institute necessary measures during the construction period, including necessary compaction of any fill material placed around newly installed structures and/or the use of silt screens, hay bales, seeding and mulching, and/or other similar techniques, to reduce erosion, turbidity, nutrient loading and sedimentation in the receiving waters.

3. Correction of Water Quality Problems

The Licensee shall be responsible for the correction of any sedimentation, turbidity, erosion, shoaling and/or maintenance of the works authorized under this Certification.

4. Off-Site Conveyances

All off-site conveyances during construction and development of the transmission line and associated access roads shall be made only through the conveyance facilities authorized by this Certification. No roadway or structure pad construction shall commence on-site unless in conjunction with the construction of the permitted conveyance facilities and any associated detention areas. Water conveyed from the project shall be through facilities having a mechanism suitable for regulating upstream water stages. Stages may be subject to operating schedules satisfactory to the SFWMD.

5. Additional Water Quality Requirements

The Licensee may be required to incorporate additional water quality treatment methods into the surface water management system if such measures are shown to be necessary.

6. Access Roads

The Licensee shall, whenever available, utilize adjacent existing roads for access to the transmission line right of way for construction, operation and/or maintenance purposes. Finger roads connecting the existing roads to the structure pads and access roads which must be constructed in areas where an existing road is not available shall be constructed in a manner which does not impede natural drainage flows and minimizes impacts to on-site and adjacent wetlands.

7. Correction of Drainage Problems

The Licensee shall be responsible for the correction of any adverse on-site, upstream, and/or downstream drainage and/or wetland impacts which may occur as a result of the construction of the proposed access road and/or structure pads. These may include the placement and/or removal of culverts and/or other structures to remedy the impact.

8. Modifications

Subsequent modifications to the drawings and supporting calculation submitted to the SFWMD which may alter the quantity and/or quality of waters discharged off-site shall be made pursuant to Section 403.516, F.S., and Rule 62-17.211, F.A.C. They shall also be submitted to the SFWMD for a determination that the modifications are in compliance with the non-procedural requirements of Chapters 40E-2 and 40E-4, F.A.C., prior to the commencement of construction.

B. Site Specific Design Authorizations

1. Access/Maintenance Road and Structure Pads

The Licensee is authorized to construct an access/maintenance road and associated conveyance facilities for the transmission line in the areas specifically identified on Exhibits 2, 3, and 4 (Figures 6.1-2, 6.1-3, and 6.1-4). Areas where an access/maintenance road is not proposed will be accessed from existing roads.

2. Authorized Receiving Water (Transmission Line Access Maintenance Roads only)

3. Adjacent Wetlands

C. Additional Information Requirements

1. Access/Maintenance Road and Structure Pad Construction Plans

Prior to the commencement of construction of any portion of the transmission line which affects the movement of waters, the Licensee shall submit plans for any construction activities for that portion of the transmission line which may obstruct, divert, control, impound or cross waters of the state, either temporarily or permanently, to the SFWMD, consistent with the provisions of Condition IV/I.B, for a determination of compliance with the non-procedural requirements of Chapter 40E-4, F.A.C., in effect at the time of submittal. "Construction activities" in this situation shall include the placement of access/maintenance roads, culverts, and/or fill materials, excavation activities, and any related activities. All plans, detail sheets and calculations shall be signed and sealed by a Florida Registered Professional Engineer. For all construction activities, the following information, referenced to NGVD, shall be submitted:

(1) A centerline profile of existing topographic features along the proposed access/maintenance road(s);

(2) A design of the proposed access/maintenance and finger road(s) with finished elevations marked;

(3) A typical cross-section of the proposed access/maintenance and finger road(s), including relative dimensions and elevations;

(4) A cross-section of each stream or creek at the point(s) to be crossed by the proposed access/maintenance and finger road, and/or other facility;

(5) Identification of wet season water table elevations for each basin in which facilities will be located;

(6) Specifications, including supporting assumptions and calculations, showing the type and size of water control structures (pipe, culvert, equalizer, etc.) to be used, with proposed flow-line elevations marked, drainage areas identified, and design capacity verified;

(7) A cross-section of any proposed excavation areas showing the proposed depth of excavation;

(8) Calculations and supporting documentation which demonstrate that the proposed construction and/or excavation activities associated with the transmission line will not have an adverse water quantity and/or water quality impact on adjacent wetlands and/or permitted surface water management systems;

(9) If construction of the transmission line contributes to the necessity for future modifications to adjacent/existing roads, water quality treatment requirements of the requested road modifications must be addressed in the surface water management system design for the transmission line.

XXVIII. SFWMD ENVIRONMENTAL CONDITIONS

A. General

1. Wetland Avoidance

The Licensee shall avoid impacting wetlands within the transmission line corridor wherever practicable. Where necessary and feasible, the location of the structure pads, other related facilities and/or the transmission line alignment shall be varied to eliminate or reduce wetland impacts. The Licensee shall work in accordance with the submitted plans in the supplemental site certification application as supplemented by final approved construction plans. Clearing and construction activities shall be confined to the limits of the clearing zone.

2. Fill Materials

No fill materials shall be obtained from excavated wetlands or within 200 feet of functional wetlands, unless in accordance with a mitigation plan submitted in compliance with the conditions of this Certification.

3. Additional Wetlands Mitigation

The Licensee may be required to provide additional mitigation and/or other measures if wetland monitoring and/or other information demonstrates that adverse impacts to protected, restored, incorporated, and/or mitigated wetlands have occurred as a result of project-related activities.

4. Additional Environmental Review

The Licensee shall submit any proposed changes in land use, project design, and/or the treatment of on-site wetlands to the SFWMD for additional environmental review in order to determine whether any additional mitigation activities will be required.

5. Mitigation Areas

Mitigation credits shall be given for mitigation areas within both the SFWMD and the SJRWMD. Mitigation credits shall be given for acreages and activities which have also been accepted by the DEP as mitigation for impacts in areas of joint jurisdiction.

Any acreages or activities proposed by the mitigation plan and its addendum which exceed the mitigation requirements of the SJRWMD, and meet the non-procedural requirements for wetland mitigation of the SFWMD, shall be credited as mitigation for impacts within the SFWMD.

If required by SFWMD, OUC agrees to provide additional acreages and activities to offset impacts within SFWMD not credited by the Mitigation Plan (June 1991) and its addendum (Sept 1991).

B. Site Specific Design Authorizations

1. Authorized Wetland Impacts

The Licensee is authorized to construct an access/maintenance road and associated conveyance facilities for the transmission line and structure pads in the wetland areas specifically identified on Exhibits 2, 3, and 4 (Figures 6.1-2, 6.1-3, and 6.14).

2. Sandhill Crane Nest Protection

The Licensee shall protect the active sandhill crane nest located in the 0.58-acre marsh situated between stations 125 and 126 in accordance with the following requirements:

(1) The transmission line poles and structure pads shall be positioned so that the transmission line spans the marsh;

(2) Construction shall be scheduled to avoid the nesting season for sandhill cranes;

(3) The marsh shall not be disturbed in any way;

(4) The access road shall be located in the swale adjacent to the railroad rather than in the marsh.

C. Additional Information Requirements

1. Wetlands Protection

Prior to the commencement of construction of any portion of the transmission line which will be located adjacent to the wetlands identified for preservation, the Licensee shall:

(1) Stake and rope off the protected wetlands and buffer zones to prevent encroachment during construction. The stakes and ropes shall remain in place until all adjacent construction activities have been completed. Verification of staked areas by SFWMD staff shall be required prior to the commencement of and upon completion of any construction activities.

(2) Install silt screens, turbidity barriers and/or hay bales prior to any construction in or alteration of any wetlands within the project site in order to prevent adverse water quality impacts to wetlands. These barriers shall remain in place until fill material is stabilized and turbidity has returned to background levels.

2. Mitigation Plan

Prior to the commencement of construction of any portion of the transmission line which may affect wetlands, the Licensee shall submit a mitigation and monitoring plan to the SFWMD for a determination of compliance with the non-procedural requirements of Chapter 40E-4, F.A.C., including Appendix 7 (Isolated Wetlands Rule) of the Basis of Review for Surface Water Management Permit Applications in the SFWMD, in effect at the time of submittal. At a minimum, the plan shall include the following information:

(1) Locations and sizes of all proposed mitigation areas, species to be planted, planting densities, details of the proposed hydrologic regime, cross-sections showing the proposed elevations and water depths, and an estimated time schedule for completion of the construction of the mitigation areas.

(2) A wetland mitigation and/or restoration work schedule which details each specific mitigation task (e.g. grading to proper elevation, mulching, planting, regularly scheduled maintenance and monitoring, etc.) and the calendar dates for the start and completion of each task.

(3) Provisions for both quantitative and qualitative observations of wildlife utilization and the vegetative community, monthly water level readings, panoramic photographs documenting the condition of the mitigation areas, and evaluation of the success of the mitigation effort, and an annual report incorporating this information and any other relevant information. The water level readings will be taken weekly for sampling points that are accessible until demonstrated to the appropriate agency that less frequent water level readings are sufficient to demonstrate compliance.

(4) Documentation that sufficient areas have appropriately worded conditions of certification within the SFWMD and/or the SJRWMD to compensate for the proposed wetland impacts with both the water management districts.

XXIX. ST. JOHNS RIVER WATER MANAGEMENT DISTRICT

A. Water Shortages

Nothing in this certification shall be construed to limit the authority of the SJRWMD to declare a water shortage and issue orders pursuant to Section 373.175, Florida Statutes or to formulate a plan for implementation during periods of water shortage, pursuant to Section 373.246, Florida Statutes. <u>In the event of a water shortage, as declared by the SJRWMD Governing Board, the Licensees must adhere to reductions in water withdrawals as specified by the SJRWMD.</u> Pursuant to Section 403.516, Florida Statutes, in the event of a water shortage as declared by the SJRWMD governing board, DEP may seek a modification of the terms and conditions of this certification to implement the water shortage declaration and the licensees must adhere to reductions in water withdrawals as specified by SJRWMD.

B. Well Construction, Modification, Or Abandonment

Prior to the construction, modification, or abandonment of an on-site well, the Licensees must submit a completed application form for a Water Well Construction

Permit to DEP and SJRWMD. All construction, modification, or abandonment of water wells must be conducted under the supervision of a licensed water well contractor and must be performed in accordance with Chapter 40C-3, F.A.C. Construction of a well will require modification of the certification when such construction is other than that specified and described in the Site Certification Application. Prior to modification or abandonment of a well, the Licensees must file an amendment to the site certification application with DEP and SJRWMD. Upon completion of the construction, modification or abandonment of each well, the Licensees must submit to SJRWMD and DEP a completion report for the well.
[Paragraphs 16.0(c); 10.3(b)(d)(h)(i), A.H.]

C. Well Maintenance

Leaking or inoperative well casings, valves, or controls must be repaired or replaced as required to put the system back in an operative condition acceptable to the SJRWMD. Failure to make such repairs will be cause for deeming the well abandoned in accordance with Part II of chapter 373, F.S., and chapter 40C-3, F.A.C., and the rules promulgated thereunder.
[Paragraphs 16.0(d); 10.3(b)(d)(h)(i), A.H.]

D. Mitigation Of Withdrawal Impacts On Existing Legal Users

~~OUC, et al.,~~ Licensees must mitigate any adverse impact caused by withdrawals permitted herein on legal uses of water existing at the time of the initial application for the Stanton Energy Center. ~~If unanticipated significant adverse impacts occur, the~~ DEP has the right to curtail permitted withdrawal rates or water allocations if the withdrawals of water cause an adverse impact on legal uses of water which existed at the time of application. Adverse impacts are exemplified by but not limited to:

1. Reduction of water levels in an adjacent surface water body resulting in a significant impairment of the use of water in that water body.

2. Saline water intrusion or introduction of pollutants into the water supply of an adjacent water use resulting in a significant reduction of water quality; and

3. Change in water quality resulting in either impairment or loss of use of a well or water body.

[Paragraphs 9.2; 10.3(b)(d)(h)(i), A.H.]

E. Mitigation Of Impacts On Adjacent Land Uses

~~OUC, et al.,~~ Licensee must mitigate any adverse impact caused by withdrawals permitted herein on an adjacent land use which existed at the time of

Supplemental Site Certification Application for Stanton 2 and any subsequent unit. ~~If unanticipated significant adverse impacts occur, the~~ DEP has the right to curtail permitted withdrawal rates or water allocations unless the impacts can be mitigated by ~~OUC, et al~~ licensee. Adverse impacts are exemplified by, but not limited to:

1. Significant reduction in water levels in an adjacent surface water body;

2. Land collapse or subsidence off-site caused by a reduction in water levels; or

3. Damage to crops and other types of off-site vegetation.

[Paragraphs 9.4.3; 10.3(b)(d)(h)(i), A.H.]

F. Identification Tags

A SJRWMD-issued identification tag must be prominently displayed at each withdrawal site by permanently affixing such tag to the pump, head-gate, valve or other withdrawal facility as provided by Section 40C-2.401, Florida Administrative Code. ~~OUC, et al.,~~ Licensee must notify the SJRWMD in the event that a replacement tag is needed.
[Paragraphs 16.0(h); 10.3(b)(d)(h)(i), A.H.]

G. Submittals

All submittals made to demonstrate compliance with the consumptive use and water well construction conditions of this certification must have the certification number plainly labeled on the submittal.
[Paragraphs 10.3(a)-(h)(i), A.H.]

H. Maximum Annual Withdrawals

Maximum annual withdrawals from the Floridan aquifer for demineralizer/steam cycle makeup, general service water, heat recovery steam generation, wash-down, injection and power augmentation, and domestic uses combined must not exceed 321.2 million gallons per year.
[Paragraphs IO.;(a)(b)(c)(e)(f)(g), A.H.]

I. Maximum Daily Withdrawals

Maximum daily withdrawals from the Floridan aquifer for

demineralizer/steam cycle makeup, general service water, heat recovery steam generation, wash-down, injection and power augmentation, and domestic uses combined must not exceed 2.00 million gallons per day.
[Paragraphs IO.;(a)(b)(c)(e)(f)(g), A.H.]

J. Limitation On Uses Of Water

1. The maximum annual ground water withdrawals from the Floridan Aquifer for fire protection (essential use) must not exceed 2.48 million gallons per day.
[Paragraphs 10,3(a)(b)(c)(f)(I1)Q), A.H.]

2. The annual allocation of reclaimed water from the Orange County Easterly Water Reclamation Facility and surface water (stormwater and surficial groundwater) from the Orange County Landfill for power plant cooling and other power plant uses is:

~~3719.35 million gallons in 2001, and~~

~~4745.00 million gallons in 2002 and beyond.~~

4745.0 million gallons in 2006;

5,694.0 million gallons in 2007 and beyond.

Licensees must use available surface water to the maximum extent possible prior to using reclaimed water.
[Paragraphs 10.3(a)(b)(c)(f)(k), A.H.]

3. Withdrawals from the Floridan aquifer wells must not be used directly for cooling tower make-up water. The CHSEC shall utilize treated sewage effluent, treated wastewater, onsite re-use water, landfill stormwater/leachate, stormwater runoff, or direct precipitation to the makeup water supply storage pond, as cooling tower makeup water.

4. If unacceptable saline water intrusion occurs at the on-site wellfield as a result of the withdrawal authorized by this certification, DEP will revoke the allocation of ground water in this certification in whole or in part to curtail or abate the impact caused by the saline water intrusion.
[Paragraphs 10,3(b)(c)(d)(h)(i), A.H.]

5. Licensees shall diligently and in good faith pursue an agreement with Orange County to transfer up to 8.0 million gallons per day of surface water (including stormwater/surficial groundwater) from the adjacent Orange County Landfill

property for use at the Stanton Energy Center facility. Once an agreement is entered into by Licensees and Orange County, Licensees shall utilize surface water from the Landfill to the maximum extent feasible to meet the water needs of the facility. The Licensees shall submit written reports to the Department and the SJRWMD six months from the date of certification and every six months thereafter until a final agreement is reached, regarding the status of negotiations and any draft or final agreements with Orange County. Licensees shall diligently and in good faith pursue a revised cooling water supply agreement with Orange County to obtain the additional reclaimed water and surface/stormwater needed for cooling Unit B. Upon execution of the revised agreement, licensees shall provide DEP and SJRWMD with copies of said agreement. [Paragraphs 10.3 (b)(d)(Q(g)(k), A.H.]

K. Dewatering

All withdrawals from the surficial aquifer for dewatering to facilitate construction of Unit A must be retained within the Unit A stormwater detention pond.

L. Off-Site Discharges

No off-site discharges are approved from this facility, except as provided for by the overflow structure in the make-up water supply pond and the natural drainage for the duration of this certification.

M. Discharges From Make-Up Water Supply Pond

All off-site discharges, as provided for by the overflow structure in the make-up water supply pond (#20, OUC, et al.'s Figure 3.2-1), must be in compliance with water quality standards as set forth in Chapters 62-4, and 62-302, F.A.C., or such standards as issued through a variance by DEP.

N. Well Water Quality Sampling

Water quality samples must be taken in April and October of each year from each production well. The samples must be analyzed for the following parameters:

Calcium	Chloride
Magnesium	Sulfate
Sodium	Carbonate
Potassium	Bi-Carbonate (or alkalinity if pH is 6.9 or lower)

All major ion analyses must be checked for anion-cation balance and must balance within 5% prior to submission. It is recommended that duplicates be taken to allow for laboratory problems or loss. The sample analyses must be submitted to the SJRWMD by May 15 and November 15 of each year. Prior to sample collection, a minimum of 3-5 casing volumes must be removed from each well. All sampling and water quality analyses shall be performed by organizations with approved comprehensive or generic quality assurance plans on file with the DEP or a laboratory having HRS certification.

O. Water Treatment Plant Reports

By January 31 of each year, OUC, et al., must submit to the SJRWMD copies of the previous year (12 months) DEP monthly water treatment plant operating report data showing total flow from the 2 Floridan wells going to the potable water treatment plant on-site. The project name and certification number must be attached to all reports.

P. Well Water Flow Monitoring

1. OUC, et al., must maintain the continuous recorder on the Floridan aquifer monitor well. Copies of the previous year (12 months) recorder charts must be forwarded to the SJRWMD on a yearly basis. The charts must be submitted by January 31 of each year. Well Nos. 1 and 2 and all reclaimed water and stormwater delivery points must have in-line totalizing flow meters installed prior to use (not including well development). The totalizing flow meters must maintain 95% accuracy, be verifiable, and be installed according to manufacturer specifications. Documentation of proper installation of flow meters (e.g. photograph) shall be submitted to the SJRWMD within 30 days of meter placement. A site visit by SJRWMD staff can also fulfill this documentation requirement.

2. Total withdrawal from well nos. 1 and 2 and all reclaimed water and stormwater delivery points, as listed on the application, must be recorded continuously, totaled monthly, and reported to DEP and SJRWMD at least every six months using SJRWMD Form No. EN-50. The reporting dates each year will be as follows:

Reporting Period	Report Due Date
January - June	July 31
July - December	January 31

[Paragraphs 6.7.1.1; 6.7.1.2; 10.3(a)(b), A.H.]

Q. Conservation Plan

OUC, et al., must implement the conservation plan submitted to the SJRWMD in accordance with the schedule contained therein.

R. Maintenance And Calibration Of Flow Meters

1. The Licensees must maintain the meters. In case of failure or breakdown of any meter, DEP and SJRWMD must be notified in writing within 5 days of its discovery. A defective meter must be repaired or replaced within 30 days of its discovery.
[Paragraphs 6.7.1; 10.3(a)(b), A.H.]

2. OUC, et al., must have all flow meter (s) calibrated once every 3 years within 30 days of the anniversary date of certification issuance, and recalibrated if the difference between the actual flow and the meter reading is greater than 5%. SJRWMD form EN-51 must be submitted to DEP and SJRWMD within 10 days of the inspection/calibration.
[Paragraphs6.7.1; 6.7.1.8.1; 10.3(a)(b), A.H.]

S. Off-Site Discharges

1. No off-site discharges from this facility are approved, except as provided for by the overflow structure in the makeup water supply pond, and the natural drainage patterns for the duration of this certification.
[Paragraph 10.3(k), A.H.]

2. All off-site discharges, as provided for by the overflow structure in the makeup water pond, must be in compliance with water quality standards as set forth in Chapters 62-4 and 62-302, F.A.C., or such other standards, which may be imposed pursuant to a variance issued by DEP.
[Paragraph 10.3(k), A.H.]

T. Use of Lowest Quality Water

The lowest quality water source, such as reclaimed water and surface/storm water, must be used when deemed feasible pursuant to District rules and applicable state law.
[Paragraphs 10.3(f)(g), A.H.]

U. Enhancement

1. Delineation Of Limits Of Construction

Prior to construction, OUC, et al., must clearly delineate the limits of construction on-site. OUC, et al., must advise the contractor that any work within the Riparian Habitat Regulation Zone outside the limits of construction, including clearing, is a violation of this certification order.

2. Background Assessment Plan

Prior to commencement of construction, a Background Assessment Plan of the areas to be enhanced or mitigated must be submitted to the SJRWMD, DEP, and SFWMD for review and joint approval. Data obtained through the Background Assessment Plan must include the following: (a) site specific topographic survey information referenced to NGVD; (b) survey of historic and existing ordinary high, normal or chronic pool water elevations referenced to NGVD based upon biological/physical wetland indicators; (c) a narrative describing the species composition, health and extent of pre-enhanced areas; and (d) quantitative information regarding the species composition including coverage and composition of under-story, mid-canopy and canopy species.

3. Completion Of Background Assessment

The background assessment must be completed pursuant to the approved Background Assessment plan prior to construction.

4. Initiation And Completion Of Enhancement Mitigation Plan

Following completion of the background assessment, and prior to the commencement of construction associated with the transmission line or the access roads, planting and construction associated with the approved Enhancement Mitigation Plan must be initiated, and then must be completed within 12 months after initiation.

5. Criteria For Success Of Enhancement And Mitigation

Following completion of the background assessment, before any planting in the mitigation and enhancement areas, OUC, et al., must submit for the joint approval of SJRWMD, DEP, and SFWMD a plan setting forth appropriate criteria for determining success of all wetland and upland enhancement and mitigation areas.

OUC, et al., shall implement and maintain the mitigation and enhancement areas to ensure that the success criteria are achieved.

6. Monitoring Plan For Enhancement And Mitigation

Within 30 days of completion of the initial planting, OUC, et al., must submit to the SJRWMD, DER, and SFWMD for review and joint approval, two copies of a monitoring plan detailing the site specific methods to be used for monitoring the enhancement and mitigation areas, so that the achievement of the success criteria can be quantitatively and qualitatively demonstrated. The monitoring plan must include the location, size and number of monitoring quadrants or transect lines, the location and number of photographic stations, the location of the wetland(s) to be enhanced and mitigated, the location of staff gauges and/or piezometers, and other pertinent factors. OUC, et al., shall monitor the enhancement and mitigation areas until the approved success criteria has been achieved.

7. Survey Of Enhancement Areas

OUC, et al., must submit to the SJRWMD, DER, and SFWMD two (2) copies of an as-built survey of the enhancement areas certified by a registered surveyor or professional engineer showing dimensions of all planted areas, invert (s) elevation of the proposed culvert in enhancement area 3.6 (A), and the final grade of all plugged ditches. An inventory of the planted species within the wetland enhancement areas will be shown on the survey. In areas where planting occurs, the inventory must include the type, number, distribution, and size of the planted vegetation, and must be referenced to the as-built survey. The as-built survey must be submitted to the referenced agency parties within thirty (3) days of completion of the initial planting.

8. Monitoring Reports For The Enhancement And Mitigation Areas

Following joint approval of the plan referenced in Condition No. 26, OUC, et al., must furnish the SJRWMD, DEP, and SFWMD with two copies of all Monitoring Reports for the enhancement and mitigation areas describing the status of the mitigation and enhancement areas until the enhancement and mitigation areas achieve the success criteria.

9. Revisions To Enhancement And Mitigation

If it is determined that successful enhancement is not occurring based on the monitoring reports or trends, OUC, et al., must, within 30 days, provide the SJRWMD, DER and SFWMD with a narrative describing the type and causes of failure with a complete set of plans for the redesign and/or replacement planting of the mitigation and enhancement areas demonstrating that the success criteria can be achieved. Within 30 days of joint agency approval of the amended plans, OUC, et al., must implement the redesign and/or replacement planting. Following completion of such work, the success criteria as stated above or as modified by subsequent approval of the plan must again be achieved. In addition, the monitoring required by the conditions of this permit must be conducted.

V. Erosion And Sediment Control During Construction

OUC, et al., must select, implement, and operate all erosion and sediment control measures required to retain sediment on-site and to prevent violations of water quality standards as specified in Chapters 62-302 and627-4, F.A.C. OUC, et al., is encouraged to use appropriate Best Management Practices for erosion and sediment control as described in the "Florida Land Development Manual: A Guide to Sound Land and Water Management" (DER 1988). All erosion and sediment control measures must remain in place at all locations until construction is completed and the soils are stabilized. Thereafter, OUC, et al., will be responsible for the removal of the control measures (except for the control measures in the areas of fill for the unpaved access road which shall be permanent).

W. Erosion And Sediment Control During Operation

Following the completion of construction, OUC, et al., must construct and maintain a permanent protective vegetative and/or artificial cover for erosion and sediment control on all land surfaces exposed or disturbed by construction or alteration of the certified project. A permanent vegetative cover must be established within 60 days after planting or installation.

X. Incorporation Of Mitigation Plan

The proposed mitigation plan submitted to SJRWMD by OUC for the Curtis H. Stanton Energy Center, Unit 2, dated June 21, 1991, July 20, 1991, September 11, 1991, September 18, 1991, and September 19, 1991 is incorporated as a condition of this certification except where specifically superseded by certification conditions.

Y. Completion Of Surface Water Management System

Construction or alteration of the surface water management system must be completed and all disturbed areas must be stabilized in accordance with the submitted plans and certification conditions prior to use of the infrastructure for its intended purpose.

Z. Retention/Detention Storage Areas

At a minimum, all retention/detention storage areas must be constructed to rough grade prior to the placement of impervious surface within the area to be served by those facilities. To prevent reduction in storage volume and percolation rates, all accumulated sediment must be remove from the storage areas prior to final grading and stabilization.

AA. Access Road And Transmission Line Construction Plans

Final Access Road and Transmission Line construction plans must be submitted to the SJRWMD al least 30 days prior to commencement of construction. The final plans must be consistent with the plans and calculations received by the SJRWMD on July 22, 1991, such that the requirements of Chapters 40C-4, 40C-41 and 40C-42, F.A.C. continue to be met.

BB. Access Road Fill

The fill material for the access roads must satisfy the soil properties assumed in the calculations received by the SJRWMD on July 22, 1991. If fill is to be acquired on site, a plan depicting the location of the area to be used for fill for the Access Roads must be submitted to the SJRWMD at least 30 days prior to commencement of construction. Access to the on-site fill material must be shown on the plan.

CC. Contractor Review And Posting Of Conditions Of Certification

OUC, et al., must require the contractor to review and maintain a copy of this document, complete with all conditions, attachments, and exhibits, in good condition and posted on the construction site.

DD. Landfill Gas And Condensate Pipeline Construction

OUC and its contractors will maintain *in situ* flow conditions within the upland cut ditches located approximately at stations 42+50 and 44+75 during construction of the landfill gas and gas condensate pipelines. Upon completion of construction at each of these locations, OUC and its contractors shall restore the banks of the ditches to natural grade and will allow the ditches to re-vegetate naturally.

EE. Right to Enter

St. Johns River Water Management District (SJRWMD) and DEP authorized staff, upon proper identification, will have permission to enter, inspect and observe permitted and related facilities in order to determine compliance with the approved plans, specifications and conditions of this certification.
[Paragraphs 16.0(a); 10.3(a)-(h)(j), A.H.]

XXX. FLORIDA DEPARTMENT OF TRANSPORTATION

A. Construction Impact Mitigation Program

OUC et al shall develop and implement at its own expense a construction traffic impact mitigation program, after consultation with DOT, and report that will be submitted to DOT prior to commencement of construction of Stanton Unit 2. The program will detail the actions that OUC et al will take to reduce the impacts of construction traffic, which report shall address the following actions:

1. OUC et al shall actively promote and encourage car-pooling by construction companies and workers, including contractors and subcontractors, from whom it obtains construction services, and OUC shall further explore with appropriate public mass-transportation providers in the area the possibility of park-and-ride service to the site.

2. OUC et al shall utilize to the extent practicable the existing railway access to the Stanton site for the delivery of equipment and materials needed for the project construction.

3. OUC et al will explore with its contractors and subcontractors the practicability of staggering construction employee work schedules, and encourage the staggering of shifts to the extent feasible to mitigate peak hour traffic congestion problems.

4. OUC et al will consult with the appropriate Winter Park DOT personnel regarding the practicality of providing temporary traffic control devices and alteration of signal times to assist in maintaining proper traffic flow at the most affected intersections which are the intersections of Alafaya Trail with both the East-West Expressway and State Road 50.

5. OUC et al shall suggest and encourage the use by construction personnel of alternate public road access to the Stanton site as appropriate to alleviate traffic congestion.

B. Unit A - Post Certification Review Of Specific Problems

1. Pipeline Crossing of State Highway System

The applicant will comply with the requirements of the Florida Department of Transportation's Utility Accommodation Manual, Chapter 14-46, Railroad/Utilities Installation or Adjustment, Florida Administrative Code, specifically to the alignment of the pipeline in conjunction with limited access facilities, method and techniques of road crossings, requirements for permits, materials used, pavement cutting, mitigation of damages to and restoration of the facility and its environment, maintenance and safety of traffic flow and operations.

Detailed construction plans have not been provided. According to State law as well as the October 3, 1983 agreement between Orlando Utility Commission (OUC) and Orlando-Orange County Expressway Authority (OOCEA), these plans must be submitted by the applicant prior to the review and permitting of the proposed gas pipeline under State Road 528. The detailed construction plans must be submitted to the Florida Department of Transportation and OOCEA and shall demonstrate compliance with all requirements of the Department's Utility Accommodation Manual and other requirements of the Department and OOCEA.

Please note the following in the preparation of the detailed construction plans for the pipeline:

a. The pipeline should be placed as far as possible from any structural components of the bridge. It appears that the rail lines are currently located under Span 3 and are offset to the west. If so, it is recommended that the pipeline be located to the east side of the rail right of way.

b. Due care will need to be exercised when excavating beneath the bridges. The minimum vertical clearance is 23 feet.

c. Any damage to the bridge structure caused by construction activity shall be repaired by the OUC at its expense.

2. Traffic Control

Traffic control will be maintained during natural gas pipeline construction and maintenance in compliance with the standards contained in the Manual of Uniform Traffic Control Devices, Chapter 14-94, Florida Administrative Code; Florida Department of Transportation's Roadway and Traffic Design Standards; and Florida Department of Transportation's Standard Specifications for Road and Bridge Construction, whichever is more stringent.

3. Access Roads

No access roads which create new connections to the State Highway System will be created for the construction and maintenance of the natural gas pipeline. Existing access roads and temporary construction roads shall be upgraded and maintained by the applicant during construction. If such upgrading results in an alteration to the connection (i.e. a change in design, configuration or location), the alteration shall adhere to the nonprocedural standards of access management contained in Chapters 14-96, State Highway System Connection Permits, and 14-97, Access Management Classification System and Standards, Florida Administrative Code. Right of way cannot be used for staging, parking or other activities associated with construction and maintenance of the pipeline without special use permission.

4. Crossing Federal Facilities

All crossings and encroachments of limited access, federally funded facilities are variances from standards and policy and will be subject to the review and approval of the Federal Highway Administration. (U.S.C. 23)

5. Standards

The Manual on Uniform Traffic Control Devices, Florida Department of Transportation's Roadway and Traffic Design Standards, the Florida Department of Transportation's Standard Specifications for Road and Bridge Construction, and pertinent sections of the Florida Department of Transportation's Project Development and Environment Manual will be adhered to in all circumstances involving the State Highway System and other transportation facilities. (Chapters 14-96 and 14-97, Florida Administrative Code)

6. Monitoring

The Florida Department of Transportation will monitor the construction of the pipeline for procedural compliance of usage and impact on the State Highway System. The Florida Department of Transportation will be compensated by the applicant for such monitoring.

7. Placement

If the pipeline is placed in any area designated for development, improvement or expansion and has been identified as such in a Master Plan or approved environmental documents have been filed at the time of such placement, the subsequent cost of moving the pipeline shall be at the cost of the applicant.

8. Oversight

Oversight for the permitting of individual crossings or any type of encroachment on the State Highway System shall rest with the Florida Department of Transportation.

9. Natural Gas Pipeline Location

a. The natural gas pipeline shall not be located nearer than 2,500 feet from the nearest point of any runway of an airport licensed by the State of Florida, listed in the Florida section of the current edition of "United States Government Flight Information Publication, Airport/Facility Directory Southeast United States", or operated by an agency of the Federal Government. The pipeline will not be located nearer than 1,500 feet from the nearest point of take-off and landing area, listed in the preceding documents. Any above-ground facility associated with the pipeline shall be located no closer than 5,000 feet from any of the aviation facilities referenced above.

b. If the final chosen alignment for the pipeline necessarily traverses an existing fixed-guideway transit facility, the pipeline shall be buried and the applicant shall comply with the requirements of the American Railway Engineering Association for uncased gas pipelines (Manual for Railway Engineering, Chapter 1, Part 5, Pipelines) unless stipulated to be encased by the Florida Department of Transportation.

c. If the final chosen alignment for the pipeline necessarily traverses a Florida Department of Transportation owned and operated or abandoned rail corridor, the applicant shall comply with the Florida Department of Transportation's Utility Accommodation Manual and the American Railway Engineering Association, Manual for Railway Engineering, Chapter 1, Part 5, Pipelines, for uncased gas pipelines unless otherwise stipulated to be encased by the Florida Department of Transportation.

10. Borings

All borings under state roadways will maintain a minimum depth of cover as stipulated in each site permit. If the bore should fail, the applicant will abandon the effort and backfill the entire bore with materials as specified by the Florida Department of Transportation. If the bore should fail, the applicant shall stop all efforts and appraise the Florida Department of Transportation District Maintenance Engineer of the situation and any proposed action prior to attempting to recover equipment or initiating another bore.

11. Transportation Projects

Attention must be given to transportation projects currently being designed and likely to being under construction at the same time as the pipeline. Special provisions must be included in the transportation project contractor's contract to allow any utilities on the right of way.

12. Access Management to the State Highway System:

If new access is proposed, access permitting as defined in Rule Chapters 14-96, State Highway System Connection Permits, Administrative Process, and 14-97, Access Management Classification System and Standards, Florida Administrative Code, will be required.

13. Drainage:

Any drainage onto State of Florida right of way and transportation facilities will be subject to the requirements of Rule Chapter 14-86, Drainage Connections, Florida Administrative Code.

14. Overweight/Overdimensional Vehicles:

Operation of overweight/overdimensional vehicles by the applicant on State transportation facilities during construction and operation of the utility facility will be subject to the requirements of Chapter 316, Florida Statutes, and Rule Chapter 14-26, Safety Regulations and Permitting Fees for Overweight and Overdimensional Vehicles, Florida Administrative Code.

C. Unit B - Post Certification Review of Specific Problems

1. Access Management to the State Highway System:

Any access to the State Highway System will be subject to the requirements of Rule Chapters 14-96, State Highway System Connection Permits Administrative Process, and 14-97, Access Management Classification System and Standards, Florida Administrative Code.

2. Overweight or Overdimensional Loads:

Operation of overweight or overdimensional loads by the applicant on State transportation facilities during construction and operation of the utility facility will be subject to safety and permitting requirements as defined in Chapter 316, Florida

Statutes, and Rule Chapter 14-26, Safety Regulations and Permit Fees for Overweight and Overdimensional Vehicles, Florida Administrative Code.

3. Use of State of Florida Right of Way or Transportation Facilities:

Any use of State of Florida right of way and certain activities on State transportation facilities will be subject to the requirements of the Department of Transportation's Utility Accommodation Manual (Document 710-020-001), Rule Chapter 14-46, Utilities Installation or Adjustment, Florida Administrative Code, and Section 337.403, Florida Statutes.

4. Drainage:

Any drainage onto State of Florida right of way and transportation facilities will be subject to the requirements of Rule Chapter 14-86, Drainage Connections, Florida Administrative Code, including the attainment of any permit required thereby.

5. Use of Air Space:

Any structures proposed in the application which exceed 200 feet in height will be subject to an aeronautical study by the Federal Aviation Authority under the provisions of 14 CFR Part 77. If the aeronautical study finds an adverse effect on the safe and efficient use of navigable airspace, the project will require the issuance of a variance by state or local government.

D. Best Management Practices

Traffic control will be maintained during plant construction and maintenance in compliance with the standards contained in the Manual of Uniform Traffic Control Devices; Rule Chapter 14-94, Statewide Minimum Level of Service Standards, Florida Administrative Code; Florida Department of Transportation's Roadway and Traffic Design Standards; Florida Department of Transportation's Standard Specifications for Road and Bridge Construction; and the Department's Utility Accommodation Manual, whichever is more stringent. It is recommended that the applicant encourage transportation demand management techniques by doing the following:

1. Placing a bulletin board on site for car pooling advertisements.

2. Requiring that heavy construction vehicles remain onsite for the duration of construction.

If the applicant uses contractors for the delivery of any overweight or overdimensional loads to the site during construction, the applicant should ensure that its contractors adhere to the necessary standards and receive the necessary permits required under Chapter 316, Florida Statutes, and Rule Chapter 14-26, Safety Regulations and Permit Fes for Overweight and Overdimensional Vehicles, Florida Administrative Code.

XXXI. ORANGE COUNTY

A. *Building And Construction Requirements*

The licensee shall comply with the building and construction requirements of Chapter 9, Orange County Code. The licensee shall pay all appropriate fees for required building and construction permits, including inspection fees. The licensee shall not commence operations of Unit A until it receives a Certificate of Occupancy from Orange County.

B. *Conservation Area*

Prior to initiation of construction (including any impacts to wetlands), the licensee shall have a formal conservation area determination approved by Orange County.

C. *Mitigation*

Within 60 days of receipt of a formal conservation area determination and prior to initiation of construction of Unit B, including impacts to any wetlands, the Licensee shall submit to Orange County Environmental Protection Division a habitat compensation proposal or a mitigation plan to offset all wetland impacts associated with the construction of Unit B facilities. All mitigation must occur within the Econlockhatchee River Hydrologic Basin in Orange County (Chapter 15, Articles X and XI).

1) Licensee must submit information at least 90 days prior to the start of construction in the form of complete application for CAI permit for County review to show compliance with County regulations and these conditions of certification.

2) Licensee must comply with County regulations and these conditions of certification for the conservation area impacts prior to commencing construction of the Unit B Project. Within sixty (60) days of receipt of the information in 1) above, the County shall notify the licensee and the FDEP in writing of whether the licensee has shown compliance with the County's relevant regulations for mitigation in the conservations area, and these conditions of certification. Within 90 days of receipt of the information in paragraph b; the FDEP shall notify the licensee of its compliance or noncompliance with the County's relevant regulations for mitigation in the conservation area, and these conditions of certification.

3) At least forty-eight (48) hours prior to commencement of construction activity for Unit B, the licensee shall submit to the Orange County Environmental Protection Division (EPD), a "Construction Notice" (form CN - 001-04) indicating the actual start date and expected completion date of the construction activities.

4) Prior to construction, the licensee must clearly designate the limits of construction on-site. The licensee must advise the contractor that any work outside the limits of construction, including clearing, may be a violation of these conditions of certification.

5) The licensee must require the contractor to maintain a copy of the conditions of certification, complete with all approved drawing, plans, conditions, attachments, exhibits, and modifications in good condition at the construction site. The licensee must require the contractor to review the County's determination of compliance prior to commencement of the activity authorized by this conservation area impact review. The complete conditions of certification must be available upon request by Orange County staff.

6) Orange County's review does not release the licensee from complying with all other federal, state, and local government rules and regulations. If these conditions conflict with those of any other regulatory agency, the licensee must comply with the most stringent conditions.

7) Should any other regulatory agency require changes to the conditions of certification, the licensee shall provide written notification to the Orange County EPD of the change prior to implementation so that a compliance review can be made.

8) The Orange County EPD must be furnished "as built" drawings to ensure that no modification has been made during the construction plan process.

9) The licensee shall immediately notify the Orange County EPD in writing of any previously submitted information that is later discovered to be inaccurate.

10) Orange County EPD staff, with proper identification, shall have permission to enter, inspect, sample and test the system to insure conformity with the plans and specifications approved by the certification at any reasonable time.

11) All excess lumber, scrap wood, trash, garbage, etc., shall be removed from the preservation areas and/or surface water(s) immediately.

12) Any unapproved impacts to wetlands and/or littoral zone as a result of the construction activity shall result in the licensee restoring the impacted area within thirty days of completion of the project and shall be done to the satisfaction of the Orange County EPD.

13) A copy of the National Pollutant Discharge Elimination System (NPDES) Notice of Intent to use a Construction General Permit for stormwater discharges that is submitted to FDEP shall also be sent to the Orange County EPD and copied to the Orange County EPD NPDES Administrator prior to start of construction.

14) Conservation areas required by Orange County regulations must be clearly marked with signage that identifies the wetland and upland buffer. These signs must be installed every 50 feet on any open space and on every individual lot or parcel line. The signs must be installed prior to issuance of a plat, certificate of completion, or issuance of building permits, whichever is first.

15) Any wetland and upland buffers shall be monitored on a bi-annual basis with monitoring reports submitted to the Orange County EPD no later than one month after the on-site evaluation has occurred.

16) Any adverse direct or secondary wetland and/or surface water impacts related to construction and/or operation of the Unit B project must be mitigated for in accordance with county mitigation regulations and these conditions of certification.

D. Public Works Impacts

1. Licensee agrees to submit to the Orange County Public Works Department a certified maintenance of traffic plan prepared by a Professional Engineer in a form that complies with the rules, regulations, standards and criteria of the County.
2. Licensee and its contractors must adhere to applicable Florida Department of Transportation and Orange County regulations when transporting materials and equipment to the site.

E. Cooling Water

Licensee will receive the additional 2.6 million gallons of cooling water supply to be provided by Orange County. Because the necessary infrastructure requirements to deliver this flow have not been sufficiently evaluated by the licensee, the delivery terms and conditions for this unit are not defined at this time and, if necessary, will be addresses in an amendment to the First Amendment To and Restatement of the Substitute Agreement between Orange County and OUC relating to Cooling Water Supply dated March 25, 2003.

F. Air

{By Agreement}: Upon Unit B achieving commercial operation, the licensee shall operate the facility such that an equivalent NO_X emission increase (TPY) is yielded which is superior to that which would have otherwise been authorized via a Department Determination of Best Available Control Technology (BACT). Accordingly, there shall be no net increase (i.e., zero TPY) in facility-wide NO_X emissions as a result of the new Unit B. Further, the licensee shall comply with the Federal Clean Air Interstate Rule (CAIR) and the implementing State rules.

Licensee and Orange County agree to identify community-based projects that will provide environmentally beneficial NO_X, greenhouse gas and/or toxic emission reductions within Orange County. Licensee agrees to co sponsor with the County these mutually agreed upon community-based projects and fund these projects in the amount of $1,000,000.00 contributed in an amount no less than $100,000.00 annually until such time Licensee has contributed a total of One Million Dollars toward the community-based projects. The ten-year period will begin on January 1, 2008, or the start of construction of Unit B, whichever occurs first.

Licensee agrees to co sponsor with Orange County mutually agreed upon qualified Renewable Energy projects within Orange County. These projects will be mutually agreed upon and Licensee agrees to fund $1,000,000 over a ten-year period for this purpose. The ten-year period will begin January 2007 or upon receipt of regulatory approval for the project, whichever occurs first.

XXXII. DEPARTMENT OF COMMUNITY AFFAIRS

The Licensee shall develop a comprehensive hurricane preparation and recovery plan for the Stanton Unit A generating unit as a component of the Stanton Energy Center. The plan shall be submitted to the Department of Community Affairs and the Orange County Office of Emergency Management no later than commencement of construction of Unit A. The Licensee shall formally update the plan every 5 years following commercial operation of Unit A or whenever an additional electrical generating unit is brought into commercial service at Stanton Energy Center and shall submit these updated versions of the plan to the Department of Community Affairs and the Orange County Office of Emergency Management.

If the Department of Community Affairs deems the plan or any of its periodic updates not to be in compliance with the requirements of this condition, it may petition for enforcement of this condition pursuant to the Florida Electrical Power Plant Siting Act.

History

Certification for Unit 1 issued 12/15/82; signed by Governor Graham
Certification for Unit 2 issued 12/17/91; signed by Governor Chiles
Modified 04/05/93; signed by Secretary Wetherell
Modified for Alafaya Trail Extension 07/24/95; signed by Governor Chiles
Modified to merge certification for Unit 1 & 2 12/24/97; signed by Secretary Wetherell
Modified 08/07/98; signed by Secretary Wetherell
Supplemental Certification for Unit A 09/21/01; signed by Governor Bush
Modified 02/24/03; signed by Siting Administrator Oven

ATTACHMENT

ATTACHMENT A: DRAFT PSD PERMIT NUMBER PSD-FL-373
FIGURE 4-2 FOR CONDITION XXI. RED COCKADED WOODPECKER

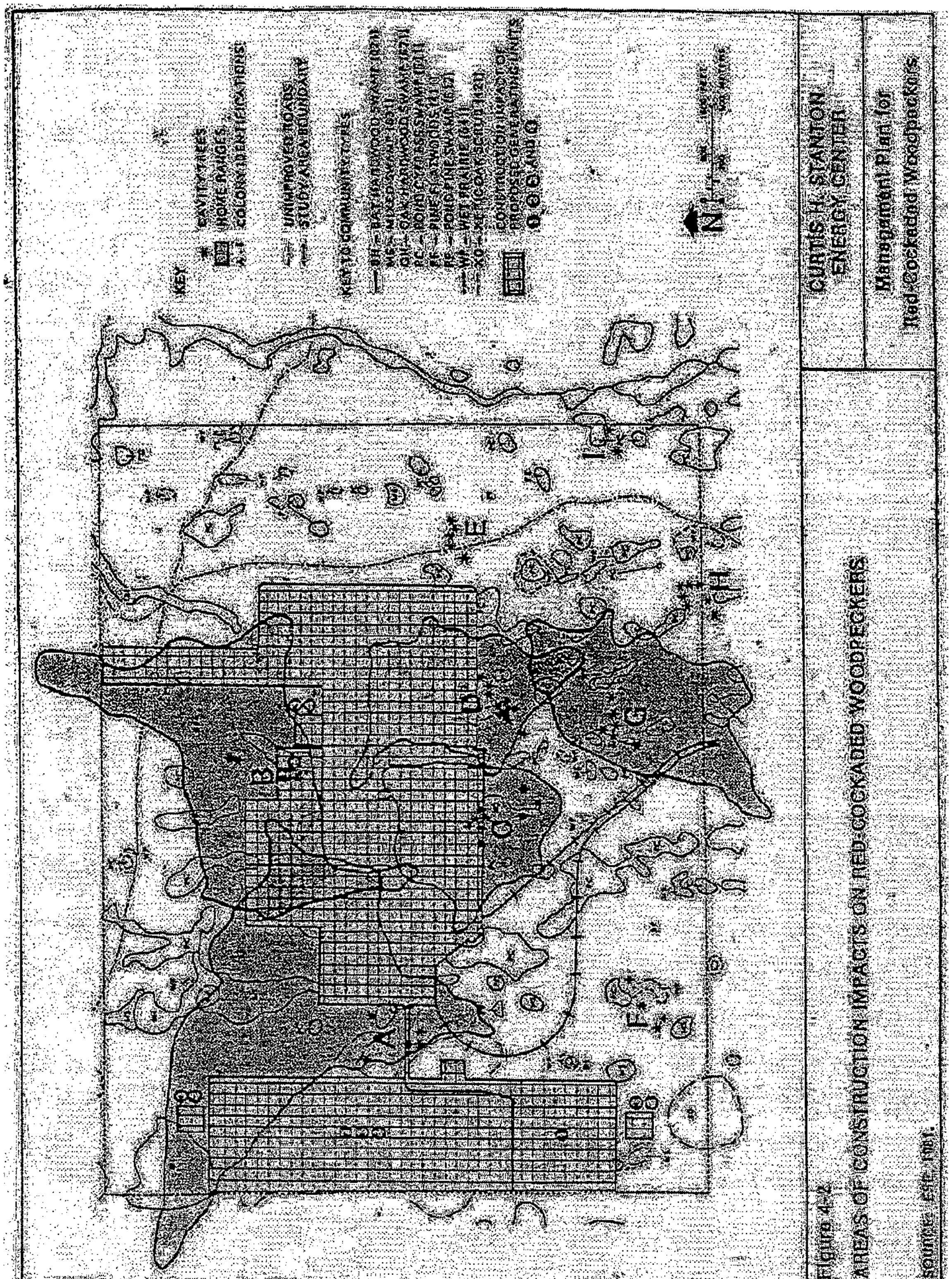

Figure 4-2
AREAS OF CONSTRUCTION IMPACTS ON RED-COCKADED WOODPECKERS

Department of Environmental Protection

DEPARTMENT OF ENVIRONMENTAL PROTECTION
JUL 27 2006
SITING COORDINATION

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: (850) 488-0114 FAX: (850) 922-6979

Colleen M. Castille
Secretary

July 26, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Frederick F. Haddad Jr., V.P. Power Resources
Orlando Utilities Commission (OUC)
Post Office Box 3193
Orlando, Florida 32802

Re: Curtis H. Stanton Energy Center Unit B
Integrated Coal Gasification and Combined Cycle
DEP File No. 0950137-010-AC (PSD-FL-373, PA 81-14SA3)

Dear Mr. Haddad:

Enclosed is the Department's preliminary determination to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to OUC and Southern Company – Orlando Gasification LLC to construct a nominal 285 megawatt integrated coal gasification and combined cycle unit at the Curtis H. Stanton Energy Center in Orange County. The documents include: the "Intent to Issue PSD Permit"; the "Public Notice of Intent to Issue PSD Permit"; the Department's "Technical Evaluation and Preliminary Determination", and "Addendum to the Technical Evaluation and Preliminary Determination"; and the revised Draft Permit. This action withdraws the action of June 16, 2006.

The PUBLIC NOTICE must be published one time only in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. According to Paragraph 62-17.135(1)(c), F.A.C. the applicant shall have published the notice no later than 10 days after the preliminary determination has been issued. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero at the above letterhead address. If you have any questions, please call Debbie Nelson at 850/921-9537 (meteorologist), or Cindy Mulkey at 850/921-8968 (review engineer).

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

TLV/cm

Enclosures

ATTACHMENT A TO EXHIBIT A

PERMITTEE:

OUC/Southern Power Company – Orlando Gasification, LLC
5100 South Alafaya Trail
Orlando, Florida 32831

Authorized Representative:
Frederick F. Haddad, Jr., V.P. Power Resources

Curtis H. Stanton Energy Center	
IGCC Unit B	
Draft Permit No.	PSD-FL-373
Project No.	0950137-010-AC
Siting No.	PA 81-14SA3
Expires:	July 31, 2010

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 285 MW coal fueled integrated gasification combined cycle electric utility steam generating unit at the existing Curtis H. Stanton Energy Center. The facility is located southeast of Orlando, in Orange County. The project is a Commercial Demonstration Project receiving funds from the Department of Energy under the Clean Coal Power Initiative.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans and other documents on file with the Department of Environmental Protection (Department).

DRAFT
Joseph Kahn, P.E., Acting Director
Division of Air Resource Management

Date:______________________

SECTION I - GENERAL INFORMATION

FACILITY DESCRIPTION

The regulated emissions units at the existing Stanton Energy Center include two coal fired boiler steam electric generating stations; solid fuels, fly ash, limestone, gypsum, slag, and bottom ash storage and handling facilities; two combustion turbine electrical generator combined cycle units capable of firing either natural gas or fuel oil; and one distillate fuel oil storage tank.

PROJECT DESCRIPTION

The project is for the addition of a nominal 285 Megawatt (net) integrated Gasification Combined Cycle (IGCC) unit (Stanton Unit B) and auxiliary equipment. The project consists of: a nominal 160 MW General Electric 7F combustion turbine-electrical generator capable of firing synthesis gas (syngas); a supplementary-fired heat recovery steam generator (HRSG); a nominal 135 MW steam-electrical generator; a 205-foot stack; a mechanical draft cooling tower with drift eliminators; a gasification system including air blown coal gasification reactor/s (KBR Transport Gasifier), a multipoint ground flare, a 184-foot gasifier startup stack, and a coal and gasification ash storage and handling area. The gasification train includes a high temperature syngas cooler, a high temperature high pressure filtration system, a low temperature gas cooling and mercury removal system, a sulfur removal and recovery process, and a sour water treatment and ammonia recovery process. Natural gas will be used as a backup fuel to the combustion turbine.

EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units:

EU ID NO.	EMISSION UNIT DESCRIPTION
030	Unit B Integrated Gasification Combined Cycle – Consists of one General Electric PG7241 FA gas turbine electrical generator (nominal 160 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, a steam turbine electrical generator (nominal 135 MW), and the gasification system associated with one gasifier startup stack.
031	Unit B Flare – A multipoint flare (including 8 pilot flares) enclosed in a 20 foot thermal barrier fence used to combust syngas during startups (once the gasifier switches fuels from natural gas to coal) and during plant upset conditions.
032	Unit B Cooling Tower – consisting of six cells with six individual exhaust fans.
033	Unit B Coal Mill and Coal Storage – including coal crushing, and crushed coal storage, coal pulverizing and feed preparation.
034	Unit B Gasification Ash Storage – including fly ash storage silo and baghouse.
035	Unit B Coal Handling – including coal conveying and transfer.

REGULATORY CLASSIFICATION

Title III: The facility is a "Major Source" of hazardous air pollutants (HAPs).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "Major Source" of air pollution in accordance with Chapter 62-213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC).

PSD: The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a "fossil fuel-fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the facility categories listed at 62-210.200(definitions, Major Stationary Source) with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 F.A.C., Prevention of Significant Deterioration (PSD).

NSPS: The following New Source Performance Standards of 40 CFR 60 may be potentially applicable to the IGCC Unit B as described in Section III, Subsection A, Federal Requirements of this permit.

- Subpart Da (Standards of Performance for Electric Utility Steam Generating Units For Which Construction is Commenced After September 18, 1978).
- Subpart KKKK (Standards of Performance for Stationary Combustion Turbines).

The coal storage and handling facilities of Unit B are subject to Subpart Y (Standards of Performance for Coal Preparation Plants).

NESHAP: The facility is a "Major Source" of HAPs and Unit B is subject to the applicable requirements of 40 CFR 63, Subpart YYYY (National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines) as described in Section III, Subsection A, Federal Requirements of this permit.

CAIR: As an electric generating unit, Unit B may be subject to the Clean Air Interstate Rule pending the finalization of DEP rules.

CAMR: Unit B is a new coal-fired power plant and may be subject to the Clean Air Mercury Rule pending finalization of DEP rules.

Siting: The facility is a steam electrical generating plant and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Protection Central District, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A	NSPS and NESHAP Subparts A, Identification of General Provisions
Appendix BD	Final BACT Determinations and Emissions Standards
Appendix Da	NSPS Subpart Da Requirements for Electric Utility Steam Generating Units
Appendix GC	General Conditions
Appendix KKKK	NSPS Subpart KKKK Requirements for Stationary Combustion Turbines
Appendix SC	Standard Conditions

Appendix Y	NSPS Subpart Y Requirements for Coal Preparation Plants
Appendix YYYY	NESHAP Subpart YYYY Standard for HAPs for Stationary Combustion Gas Turbines

RELEVANT DOCUMENTS:

The documents listed below are not a part of this permit, however they are specifically related to this permitting action and are on file with the Department.

- February 17, 2006: Received Site Certification Application (SCA) including PSD application.
- April 5, 2006: Sent Sufficiency Issues to DEP Siting Coordination Office (SCO).
- April 10, 2006: SCA determined to be Insufficient by SCO.
- May 8, 2006: Received Sufficiency Responses from Applicant.
- May 26, 2006: Sent Status Letter on Sufficiency Responses.
- July 26, 2006: Intent to Issue PSD Permit distributed.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 63, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Construction and Expiration: Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of the permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

5. Source Obligation.

   a. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   b. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   [Rule 62-212.400(12), F.A.C.]

6. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning

construction or modification. This permit authorizes construction of the referenced facilities. [Chapters 62-210 and 62-212, F.A.C.]

7. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

8. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. Unit B Integrated Gasification Combined Cycle (EU 030)

The specific conditions of this subsection apply to the following emissions unit after construction is complete.

E.U. ID	Emission Unit Description
030	Unit B Integrated Gasification Combined Cycle – Consists of one General Electric PG7241 FA gas turbine electrical generator (nominal 160 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, a steam turbine electrical generator (nominal 135 MW), and the gasification system associated with one gasifier startup stack.

The integrated gasification combined cycle unit contains the following emissions points.

Point ID	Emissions Point Description
GCC-1	CT/HRSG Stack
GCC-2	Gasifier Startup Stack

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: A determination of the Best Available Control Technology (BACT) was made for carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOCs). [Rule 62-210.200 (BACT), F.A.C.]
2. NO_X Emissions Cap: An emissions cap on Units 1 and 2 was taken in order for the project to "net out" with respect to NO_X emissions, thus avoiding a BACT determination for nitrogen oxides.
3. NSPS Requirements: This unit may be subject to the subparts of 40 CFR 60, listed and as described below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that the BACT emissions performance requirements are as stringent as or more stringent than the limits imposed by the applicable NSPS provisions for SO_2 and PM. Some separate reporting and monitoring may be required by the individual subparts.
   a. The Unit is subject to Subpart A, General Provisions, including:
      - 40 CFR 60.7, Notification and Recordkeeping
      - 40 CFR 60.8, Performance Tests
      - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
      - 40 CFR 60.12, Circumvention
      - 40 CFR 60.13, Monitoring Requirements
      - 40 CFR 60.19, General Notification and Reporting Requirements
   b. **Subpart Da, Standards of Performance for Electric Utility Steam Generating Units.** These provisions include standards for duct burners and certain heat recovery steam generators and associated stationary combustion turbines. Subpart Da may be applicable to the new IGCC Unit B as described in Section III, Subsection A, Federal Requirements of this permit.
   c. **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** These provisions include standards for stationary combustion turbines constructed after February 18, 2005. Subpart KKKK may be applicable to the new IGCC Unit B as described in Section III, Subsection A, Federal Requirements of this permit.

4. NESHAP Requirements: The combustion turbine is subject to 40 CFR 63, Subpart A, Identification of General Provisions and 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines as described in Section III, Subsection A, Federal Requirements of this permit.

EQUIPMENT DESCRIPTION

5. Combustion Turbine: The permittee is authorized to install, tune, operate, and maintain one General Electric Model PG7241FA gas turbine-electrical generator set with a nominal generating capacity of 160 MW. The combustion turbine will be equipped with GE's diffusion flame multinozzle quiet combustor (MNQC), and an inlet air filtration system with evaporative coolers. The combustion turbine will be designed for operation in an IGCC mode, will have dual-fuel capability and shall be designed for a maximum heat input rate of 1,942 mmBtu per hour when firing natural gas and 1,818 mmBtu per hour when firing syngas (based on a compressor inlet air temperature of 20° F, the higher heating value (HHV) of the fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Application; Design]

6. HRSG: The permittee is authorized to install, operate, and maintain the heat recovery steam generator (HRSG) with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator. The HRSG will be equipped with supplemental gas-fired duct burners. The duct burners shall be designed for a maximum heat input rate of 531.5 mmBtu per hour based on the higher heating value (HHV) of natural gas. [Application; Design]

7. Generating Capacity: Unit B will have a nominal electrical generating capacity of 285 MW (net) when firing syngas and 310 MW when firing natural gas (duct burners operational).

8. Gasification System: The permittee is authorized to install, operate, and maintain a gasification system, consisting of air blown gasifier/s and one startup stack, for the production of synthesis gas to be fired in the combustion turbine. The gasification system includes the transport gasifier/s, a high temperature syngas cooler, a high temperature high pressure filtration system, a low temperature gas cooling and mercury removal system, a [illegible] removal and recovery system, and a sour water treatment and ammonia recovery system. The gasification system shall be designed for a maximum total gasification heat input rate of 2,397 mmBtu per hour (based on an ambient air temperature of 20° F, the higher heating value (HHV) of the fuel, and 100% load). [Application; Design]

CONTROL TECHNOLOGY

9. Combustion Turbine/HRSG: The following pollution control equipment shall be installed and operated as specified below:

   a. *Steam Injection:* The permittee shall install, operate, and maintain a steam injection system to reduce NO_X emissions from the combustion turbine when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the steam injection system shall be tuned to achieve permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

b. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from the combustion turbine when firing natural gas, synthesis gas, or a combination thereof. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to meet the permitted levels of NO_X and NH_3 emissions.

Ammonia Storage: In accordance with 40 CFR 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

c. *Oxidation Catalyst*: Between 21 and 27 months following the completion of all initial compliance testing required under this permit, the permittee shall install, operate, and maintain an oxidation catalyst designed and intended to reduce CO emissions from the combustion turbine when firing natural gas, synthesis gas, or a combination thereof to 4.1 ppmvd @ 15% O_2. Two years following original installation of this oxidation catalyst, permittee shall, in its sole discretion, become authorized to remove the catalyst at any time. Permittee shall only remove the catalyst prior to the end of this two year period if the project representative for the Department of Energy expressly concurs with a recommendation from the permittee, which recommendation shall be provided concurrently to the Department, for its removal based on the inability to achieve Department of Energy demonstration objectives with the CO catalyst remaining in place, or based on serious, actual maintenance problems associated with the catalyst installation. Permittee shall maintain records on performance of the catalyst in accordance with any DOE demonstration obligations. Upon removal of the initial CO catalyst, the permittee shall return a sample of the catalyst to the vendor for evaluation of relevant commercial properties and use its best efforts to provide the Department with subsequent evaluation results.

[Design; Rules 62-210.200(PTE, and BACT), 62-210.650, 62-212.400(PSD), F.A.C.; Chapter 403.061, F.S.]

10. Gasification System: The following technologies shall be installed and operated for each gasifier train for treatment of the synthesis gas stream prior to combustion in the combustion turbine.

a. *Particulate Filtration System*: The permittee shall install, operate, and maintain a high temperature/high pressure (HTHP) filtration system for the removal of particulate matter from the synthesis gas in order to achieve the permitted levels of particulate matter emissions from the CT/HRSG system.

b. *Mercury Removal System*: The permittee shall install, operate, and maintain a mercury removal system to remove a sufficient amount of mercury from the synthesis gas stream to achieve the permitted levels of mercury emissions from the CT/HRSG system.

c. *Sulfur Removal System*: The permittee shall install, operate, and maintain a sulfur removal system to remove a sufficient amount of sulfur from the synthesis gas stream to achieve the permitted levels of SO_2 and H_2SO_4 emissions from the CT/HRSG system.

d. *Ammonia Recovery*: The permittee shall install, operate, and maintain an ammonia removal system to remove a sufficient amount of ammonia from the synthesis gas stream to help achieve the permitted levels of NO_X.

Ammonia Storage: In accordance with 40 CFR 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

[Design; Rule 62-212.400(PSD), F.A.C.]

PERFORMANCE REQUIREMENTS

11. Hours of Operation: The gasification system and/or gas turbine may operate throughout the year (8,760 hours per year). Restrictions on individual methods of operation are specified in separate conditions. [Rules 62-210.200(PTE, and BACT) and 62-212.400 (PSD), F.A.C.]

12. Authorized Fuels:

    a. *Synthesis Gas* - The combustion turbine may fire synthesis gas produced in the gasification system.

    b. *Natural Gas* -The combustion turbine may fire natural gas which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. Only natural gas shall be fired in the duct burners, and used for initial startup of the transport gasifier/s.

    c. *Synthesis Gas/Natural Gas Combination* – The combustion turbine may fire a synthesis gas/natural gas mixture. An hour in which a synthesis gas/natural gas fuel mixture is fired is subject to the BACT limits for natural gas when the mixture contains greater than 75% natural gas (by heat input), and subject to the BACT limits for synthesis gas when the mixture contains 75% or less natural gas (by heat input) for that hour.

    d. *Coal* – When burning synthesis gas in the combustion turbine, coal shall be processed in the gasification island.

    [Rules 62-210.200(PTE, and BACT) and 62-212.400 (PSD), F.A.C.]

13. Methods of Operation of the Combustion Turbine: Subject to the restrictions and requirements of this permit, the gas turbine may operate under the following methods of operation.

    a. *Combined Cycle Operation*: The combustion turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall, to the extent practicable (considering availability and reliability of the unit), be on line and functioning properly during combined cycle operation, or when the HRSG is producing steam. The permittee shall keep records documenting the duration and reason for any period when the SCR system is not in operation. These records shall be made available to the Department upon request.

    b. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as fogging.

    c. *Duct Firing*: The HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power.

    [Application; Rules 62-210.200(PTE, and BACT), 62-210.650, and 62-212.400 (PSD), F.A.C.]

14. Methods of Operation of the Gasifiers: Subject to the restrictions and requirements of this permit, the gasification island may operate under the following methods of operation.

    a. *Initial Startup:* During startup of the gasification island, gasifier gas may be vented to the gasifier startup stack after passing through the particulate filtration system. As soon as possible, upon reaching a reducing atmosphere within the gasifier, the exhaust synthesis gas shall be directed to the flare and not to the startup stack. At no time, other than initial startup, shall the exhaust gases be directed to the startup stack.

    b. *Synthesis Gas Flaring:* Once the gasifiers reach a reducing atmosphere, synthesis gas shall be directed through the gas clean-up processes to the flare. Flaring during startup shall take place only until there is sufficient synthesis gas production to support operation of the combustion turbine. Operation of the combustion turbine may be accomplished by mixing the synthesis gas with natural gas. Synthesis gas may be directed to the flares during upset conditions such as trips of the CT/HRSG system to allow safe release of the pressurized gas.

c. *Integrated Operation:* The gasification system may operate to produce synthesis gas for combustion in the combustion turbine. All control equipment/technologies constructed to treat the gas stream prior to combustion of the synthesis gas in the combustion turbine shall be on line and functioning properly, in accordance with the specifications of the manufacturers, during the integrated operation of the gasification and CT/HRSG systems.

[Application; Rules 62-210.200 (PTE, and BACT) and 62-212.400 (PSD), F.A.C.]

EMISSIONS AND TESTING REQUIREMENTS

15. Emission Standards: Emissions from the turbine/HRSG system shall not exceed the following standards.

Best Available Control Technology (BACT) - Rule 62-210.200, F.A.C.			
While Firing Natural Gas[a]			
Pollutant	Stack Test, 3-Run Average		CEMS Average
	ppmvd @ 15% O_2	[illegible][e]	
CO (DB)[f]	27.2/4.1	138.0/[illegible]	24-hr rolling
CO (w/o DB)[f]	20.5/4.1	79.0/15.8	
VOC (DB)	6.5	19.0	N/A
VOC (w/o DB)	2.4	[illegible]5.3	
SO_2[b]	2.0 gr S/100 SCF of gas		N/A
SAM[b]	2.0 gr S/100 SCF of gas		N/A
PM/PM_{10}[c]	[illegible]0 gr S/100 SCF of gas		N/A
	10 % opacity, 6-minute block average		
Ammonia[d]	5.0	N/A	N/A
While Firing [illegible][a]			
CO (DB)	20.[illegible]	140.5	24-hr rolling
CO (w/o DB)	15.8	90.7	
VOC (DB)	4.6	17.9	N/A
VOC (w/o DB)	2.4	7.9	
SO_2[b]	2.7	35.5	30-day rolling
PM/PM_{10}	Compliance with SO_2/CO standards		N/A
	10 % opacity, 6-minute block average		
SAM[b]	Compliance with SO_2		N/A
Ammonia[d]	5.0	N/A	N/A

PSD Preconstruction Review Avoidance – Rule 62-212.400(2)(a), F.A.C.				
Pollutant	Fuel	ppmvd @ 15% O_2	TPY	CEMS Average
NO_X	Natural Gas	15.0	N/A	30-day rolling
	Syngas	20.0		30-day rolling
	Natural Gas/Syngas	N/A	1,006	12-month rolling
Mercury	Natural Gas/Syngas	10 x 10^{-6} lb/MWh	29 lb/yr	12-month rolling

a. For purposes of meeting the BACT limits of this subsection, an hour in which a synthesis gas/natural gas fuel mixture is fired, is subject to the BACT limit for natural gas when the mixture contains greater than 75% natural gas (by heat input), and subject to the BACT limit for synthesis gas when the mixture contains 75% or less natural gas (by heat input) for that hour. Any hour in which both synthesis gas and natural gas are combusted in the combustion turbine due to fuel switching, shall be subject to the limits for synthesis gas firing.

b. The fuel sulfur specifications, established in Condition [illegible] of this subsection, effectively limit the potential emissions of SO_2 and SAM from the combustion turbine while firing natural gas and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 49 of this subsection. BACT for SO_2 while firing synthesis gas has been determined as 2.7 ppmvd and 35.5 lb/hr. Compliance with the SO_2 limit effectively limits the potential emissions of SAM while firing synthesis gas.

c. The fuel sulfur specifications for natural gas and the [illegible] standard for syngas, combined with the efficient combustion design and operation of the combustion turbine represent BACT for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion.

d. The SCR system shall be designed and operated for an ammonia slip limit of no more than 5 ppmvd corrected to 15% O_2 based on the average of three test runs. Notwithstanding this provision, ammonia slip may exceed 5 ppmvd but may not exceed 10 ppmvd corrected to 15% O_2 when the SCR system is voluntarily operated to reduce NO_X emissions below 10 ppmvd.

e. Mass emission rate standards and concentrations are based on 100 percent full load operation, an ambient temperature of 70 [illegible] using the [illegible]HV of the fuel. The mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

f. The emission standards for CO when firing natural gas shall be determined in accordance with Condition 16.a of this subsection.

{Permitting Note: The above emissions standards effectively limit annual potential emissions from the combustion turbine/HRSG system to: 615 tons/year of CO, 83 tons/year of VOC, 155 tons/year of SO_2, less than 24 tons/year of SAM, and less than 156 tons/year of PM/PM_{10}.}

[Rules 62-4.070(3), 62-212.400 (BACT), and 62-212.400(PSD), F.A.C]

16. <u>Carbon Monoxide (CO)</u>: Emissions of CO from the CT/HRSG system shall not exceed the following BACT limits on a 24-hr rolling average as measured by the required CEMS and during the required stack tests.

  a. *While firing natural gas CO emissions shall not exceed:*

    Duct burners on – 27.2 ppmvd @ 15% O_2 and 138.0 lb/hr

    Duct burners off – 20.5 ppmvd @ 15% O_2 and 79.0 lb/hr

However, beginning with the 10th calendar year after the completion of the initial compliance tests, and for each calendar year thereafter, if, excluding startup, the total natural gas heat input to the combustion turbine for the prior 48 months exceeds 50% of the total heat input to the combustion turbine for that period, then CO emissions thereafter for the life of the permit shall not exceed:

Duct burners on – 4.1 ppmvd @ 15% O_2 and 20.8 lb/hr

Duct burners off – 4.1 ppmvd @ 15% O_2 and 15.8 lb/hr

b. *While firing synthesis gas CO emissions shall not exceed:*

Duct burners on –20.5 ppmvd @ 15% O_2 and 140.5 lb/hr

Duct burners off – 15.8 ppmvd @ 15% O_2 and 90.7 lb/hr

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

17. Volatile Organic Compounds (VOCs): Emissions of VOC from the CT/HRSG system shall not exceed the following standards as determined by data collected during the required stack tests:

a. *While firing natural gas, VOC emissions shall not exceed:*

Duct burners on –6.5 ppmvd @ 15% O_2 and 19.0 lb/hr

Duct burners off –2.4 ppmvd @ 15% O_2 and 5.3 lb/hr

b. *While firing synthesis gas, VOC emissions shall not exceed:*

Duct burners on – 4.6 ppmvd @ 15% O_2 and [illegible] lb/hr

Duct burners off – 2.4 ppmvd @ 15% O_2 and 7.9 [illegible]

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

18. Sulfur Dioxide (SO_2):

a. *While firing natural gas:*

The fuel sulfur specifications, established in Condition 12 of this subsection, of 2.0 grains per 100 standard cubic feet effectively limit the [illegible] emissions of SO_2 while firing natural gas from the comb[illegible]

b. *While firing synthesis gas*: Emissions of SO_2 from the CT/HRSG system shall not exceed 2.7 ppmvd @ [illegible]% O_2 and 35.5 lb/hr [illegible] a 30-day [illegible] average as measured by the required CEMS and during the required stack tests.

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

19. Sulfuric Acid Mist (SAM, H_2SO_4): Sulfuric acid mist is effectively limited by the fuel sulfur specifications and the sulfur dioxide limits while burning natural gas and synthesis gas respectively. These requirements represent BACT for this pollutant. [Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

20. Particulate Matter (PM/PM_{10}):

a. *While burning natural gas*:

The fuel sulfur specifications, established in Condition 12 of this subsection, combined with the efficient combustion, design, and operation of the combustion turbine represent BACT for PM/PM10 emissions while firing natural gas. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Visible emissions shall not exceed 10 % opacity as observed during the required visible emissions tests.

b. *While burning synthesis gas:*

The SO_2 standard for synthesis gas, combined with the efficient combustion design and operation of the combustion turbine represent BACT for PM/PM_{10} emissions. Compliance with the SO_2 and CO standards, and visible emissions standard shall serve as indicators of good combustion. Visible emissions shall not exceed 10 % opacity as observed during the required visible emissions tests. Results from the particulate matter stack tests, as required in Conditions 30 of this subsection, shall be reported to the compliance authority.

{Permitting Note: The SO_2 limit of 2.7 ppm is approximately equal to [illegible] lb SO_2/mmBtu of synthesis gas which is below the sulfur dioxide fuel specification of 60.49Da([illegible])}

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C., 40 CFR 60.49, and Chapter 403.061(18), F.S.]

21. Ammonia: Ammonia slip shall not exceed 5 ppmvd @ 15% O_2 as determined by data collected during the required stack tests, except as provided in Condition 15, [illegible]d of this subsection.

22. Mercury (Hg): Emissions of mercury from the CT/HRSG system shall not exceed 10 x [illegible] lb/MWh on a 12 month rolling average based on methods and requirements as described in 40 CFR 60.45Da(b) and 60.50Da(g).
[Rules 62-4.070(3), and 62-212.400(12)(PSD Avoidance), F.A.C., and 40 CFR 60.45Da (b) and 60.50Da(g)]

23. Nitrogen Oxides (NO_X): Emissions of NO_X from the CT/HRSG system shall not exceed the following standards as measured by the required CEMS [illegible] averaging period specified, and as measured during the required stack tests.

a. *While burning natural gas:*

15 ppmvd @ 15% O_2 on a rolling 30-day average

b. *While burning synthesis gas:*

20.0 ppmvd @ 15% O_2 on a rolling 30-day average.

[Rules 62-4.070(3), and 62-212.400(PSD Avoidance), F.A.C, Applicant Request, and 40 CFR 60.4325]

24. NO_X Emis[illegible]

a. *Existing Units 1 and 2*: The combined NO_X emissions from existing coal fired boiler steam electric generating Stanton Unit 1 and Stanton Unit 2 shall not exceed 8,300 tons per year on a 12-month rolling total beginning the first month of first fire of Unit B and thereafter. Total NO_X emissions shall be based on data collected from the Unit 1 and Unit 2 NO_X CEMS and the rolling 12-month total from each unit shall be computed in accordance with Condition 46 of this subsection.

b. *New Unit B*: Total NO_X emissions from the new Unit B CT/HRSG stack, gasifier startup stack, and flare shall not exceed 1,006 tons on a 12-month rolling total. Total NO_X emissions from the CT/HRSG stack shall be based on data collected from the required NO_X CEMS and computed in accordance with Condition 46 of this subsection. Total NO_X emissions from the flare and gasifier startup stack shall be estimated in accordance with 62-210.370, F.A.C.

c. If the combined NO_X emissions from Units 1 and 2 exceed 8,300 tons during any 12-month period, and/or the total NO_X emissions from Unit B exceeds 1,006 tons during any 12-month period, Unit B shall be subject to PSD preconstruction review at that time, and a determination of BACT for NO_X shall be made.

d. For purposes of meeting the NO_X emissions caps, annual emission of NO_X from existing Units 1 and 2, and Unit B shall be calculated without the Allowable Data Exclusions of Condition 37 of this subsection. All valid hours of data (including startup and shutdown) must be included in the rolling 12-month totals. Also, the data substitution procedures of Part 75 for missing data shall not be used in these calculations.

[62-210.200 (net emissions increase), 62-210.370 (emissions computation), and 62-212.400(12) (Source Obligation), F.A.C.]

{Permitting Note: This project did not trigger PSD for NO_X due to a NO_X emissions cap taken on existing coal fired boiler steam electric generating Unit 1 and Unit 2. The above conditions establish the requirements for meeting the NO_X emission limitations for purposes of avoiding PSD preconstruction review. These requirements in no way supersede any federal requirements of the applicable NSPS or NESHAP provisions.}

25. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering, confining, or applying water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

26. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content. Methods shall be performed as necessary to support other methods.
5	Determination of Particulate Emissions. The minimum sample volume shall be 30 dry standard cubic feet.
6C	Determination of SO2 Emissions (Instrumental)
7E	Determination of NOx Emissions (Instrumental). NOx emissions testing shall be conducted with the [illegible] operating at the highest heat input possible during the test.
9	Visual Determination of Opacity
10	Measurement of Carbon Monoxide Emissions (Instrumental). The method shall be based on a continuous [illegible]
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization – Instrumental)
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source • This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/[illegible].html". The other methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

27. Testing Requirements: Initial tests shall be conducted between 90% and 100% of permitted capacity; otherwise, this permit shall be modified to reflect the true maximum capacity as constructed. Subsequent annual tests shall be conducted between 90% and 100% of permitted capacity in accordance with the requirements of Rule 62-297.310(2), F.A.C. Tests shall be conducted for each required pollutant when firing natural gas, when firing syngas, and when using the duct burners while firing each fuel in the CT. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the CEMS shall also be reported. Particulate matter testing and reporting shall include front and back half catches. Data collected from the reference method during the required CEMS quality assurance RATA tests

may substitute for annual compliance tests for those pollutants, provided the owner or operator indicates this intent in the submitted test protocol, and obtains approval prior to testing. [Rule 62-297.310(7)(a), F.A.C.; 40 CFR 60.8]

28. Initial Compliance Demonstration:

    a. *Natural Gas:* Initial compliance stack tests shall be conducted within 60 days after achieving the maximum production rate on natural gas, but not later than 180 days after the initial startup on natural gas. In accordance with the test methods specified in this permit, the combustion turbine shall be tested to demonstrate initial compliance with the emission standards for CO, SO_2, NO_X, Hg, ammonia slip, VOC, and visible emissions. The permittee shall provide the Compliance Authority with any other initial emissions performance tests conducted to satisfy vendor guarantees.

    b. *Synthesis Gas*: Initial compliance stack tests shall be conducted within 60 days after achieving the maximum heat input to the combustion turbine on synthesis gas, but not later than 180 days after the initial operation of the combustion turbine on synthesis gas. In accordance with the test methods specified in this permit, the combustion turbine shall be tested to demonstrate initial compliance with the emission standards for CO, SO_2, NO_X, Hg, ammonia slip, VOC, and visible emissions. The permittee shall provide the Compliance Authority with any other initial emissions performance tests conducted to satisfy vendor guarantees.

    [Rules 62-4.070, 62-297.310(7)(a), F.A.C. and 40 CFR 60.8]

29. Subsequent Compliance Testing: Annual compliance stack tests for CO, SO_2, NO_X, ammonia slip, VOC, and visible emissions shall be conducted during each federal fiscal year (October 1st, to September 30th). Annual testing to determine VOC emissions, visible emissions, and ammonia slip shall be conducted while firing the primary fuel. Data collected from the reference method during the CO, SO_2, and NO_X CEMS quality assurance RATA tests may be used to satisfy the annual compliance stack test requirements for these pollutants, provided the owner or operator indicates this intent in the submitted test protocol, and obtains approval prior to testing. Additional testing for CO and NO_X may be required following catalyst replacement. If normal operation on natural gas is less than 400 hours per year, then subsequent compliance testing on natural gas is not required for that year. If normal operation on natural gas exceeds 400 hours per year, the Department may require compliance testing for visible emissions, ammonia slip, and VOC emissions while firing natural gas. [Rules 62-4.070, 62-210.200(BACT), and 62-297.310(7)(a)4, F.A.C., and 40 CFR 60.50Da]

30. Additional Testing: Concurrent with initial and subsequent compliance testing, particulate matter testing (front and back half) shall be conducted while firing synthesis gas and the results shall be reported to the Department.

31. Continuous Compliance: Continuous compliance with the permit standards for emissions of CO, NO_X, and SO_2 shall be demonstrated with data collected from the required continuous monitoring systems. Compliance with the permit standards for mercury shall be demonstrated with data collected in accordance with Condition 41. [Rules 62-4.070, and 62-210.200(BACT), F.A.C., 40 CFR 60.50Da]

32. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No 15 of this subsection. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

33. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of the gas turbine, HRSG, gasification system, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

34. Definitions:

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

    [Rule 62-210.200(164, 241, and 257), F.A.C.]

35. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

36. Data Exclusion Procedures for SIP Compliance: Limited amounts of CEMS emissions data collected during startup, shutdown, and malfunction and described in Condition 37 below, may be excluded from the corresponding SIP-based compliance demonstration, provided that best operational practices to minimize emissions are adhered to, the duration of data excluded is minimized, and the procedures for data exclusion listed below are followed. As provided by the authority in Rule 62-210.700(5), F.A.C., these conditions replace the provisions in Rule 62-210.700(1), F.A.C.

    a. *Limiting Data Exclusion.* If the compliance calculation using all the CEMS emission data indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    b. *Event Driven Exclusion.* There must be an underlying event (startup, shutdown, or malfunction) in order to exclude data. If there is no underlying event, then no data may be excluded.

    c. *Continuous Exclusion.* Data shall be excluded on a continuous basis. Data from discontinuous periods shall not be excluded for the same underlying event.

37. Allowable Data Exclusions: The following data may be excluded from the corresponding SIP-based compliance demonstration for each of the events listed below:

    a. *Steam Turbine/HRSG System Cold Startup:* Up to six hours (in any 24-hr period) of excess emissions from the combustion turbine/HRSG system due to cold startup of the steam turbine/HRSG system may be excluded. A "cold startup of the steam turbine/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

{Permitting Note: During a cold startup of the steam turbine system, the gas turbine/HRSG system is brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue.}

b. *Steam Turbine/HRSG System Warm Startup:* Up to four hours (in any 24-hr period) of excess emissions from the combustion turbine/HRSG system due to warm startup of the steam turbine/HRSG system may be excluded. A "warm startup of the steam turbine/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

c. *Shutdown:* Up to three hours (in any 24-hr period) of excess emissions from the gas turbine/HRSG system due to shutdown of the combined cycle operation may be excluded.

d. *Malfunction*: Up to 2 hours (in any 24-hr period) of excess emissions from the combustion turbine/HRSG system due to a documented malfunction may be excluded. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic email.

All valid emissions data (including data collected during startup, shutdown, and malfunction) shall be used to report emissions for the Annual Operating Report.

[Rules 62-210.200(BACT), 62-210.370, and 62-210.700, F.A.C.]

38. Ammonia Injection: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer and as provided in Condition 13. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbine/HRSG system including the pollution control equipment.
[Design; Rules 62-210.200(BACT), 62-212.400(PSD), and 62-210.700, F.A.C.]

39. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate non-compliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data. [Rule 62-4.070, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

40. CEM Systems: Subject to the following, the permittee shall install, calibrate, operate, and maintain continuous emission monitoring systems (CEMS) to measure and record the emissions of CO, NO_X, and SO_2 from the combined cycle combustion turbine in terms of the applicable standards. Each monitoring system shall be installed, and functioning within the required performance specifications by the time of the initial compliance demonstration.

a. *CO Monitor*: The CO monitor shall be installed pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

b. *NO_X Monitor:* A NO_X monitor installed to meet the requirements of 40 CFR 75, and that is continuing to meet the ongoing requirements of Part 75, may be used to meet the requirements of this permit and 40 CFR 60.49(c), Subpart Da, except that the owner or operator shall also meet the requirements of 60.51Da and the specific conditions of this permit. Data reported to meet the requirements of 60.51Da and the BACT limits of this permit shall not include data substituted using the missing data procedures in Subpart D of Part 75, nor shall the data have been bias adjusted according to Part 75.

c. *SO_2 Monitor:* The SO_2 monitor shall be installed pursuant to 40 CFR 60, Appendix B, Performance Specification 2. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The RATA tests required for the SO_2 monitor shall be performed using EPA Method 7 or 7E in Appendix A of 40 CFR 60. The SO_2 monitor span value shall be set according to 60.49Da(i). Alternatively, an SO2 monitor installed to meet the requirements of 40 CFR 75, and that is continuing to meet the ongoing requirements of Part 75, may be used to meet the requirements of this permit and 40 CFR 60.49(b), Subpart Da, except that the owner or operator shall also meet the requirements of 60.51Da and the specific conditions of this permit. Data reported to meet the requirements of 60.51Da and the BACT limits of this permit shall not include data substituted using the missing data procedures in Subpart D of Part 75, nor shall the data have been bias adjusted according to Part 75.

d. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be continuously monitored at the location where CO, NO_X, and SO_2 are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

[Rules 62-4.070(3), 62-210.200(BACT), F.A.C., and 40 CFR 60.49Da and Subpart 75]

41. <u>Mercury Monitoring</u>: Mercury emissions shall be monitored in accordance with 40 CFR 60.45Da and 60.49Da. [Rules 62-4.070(3), F.A.C., and 40 CFR 60.45Da and 60.49Da.]

42. <u>Continuous Flow Monitor</u>: A continuous flow monitor shall be installed to determine stack exhaust flow rate to be used in determining mass emissions. The flow monitor shall be certified and operated according to the requirements of 40 CFR 75. As an alternative to the stack flow monitor, a fuel flow monitoring system certified and operated according to the requirements of Appendix D of 40 CFR Part 75 may be installed. [Rules 62-4.070(3), 62-210.200(BACT), F.A.C., and 40 CFR 60.49Da and Subpart 75]

43. <u>Wattmeter</u>: A wattmeter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours must be installed, calibrated, maintained, and operated in accordance with the manufacturer's specifications. [40 CFR 60.49Da]

44. <u>Moisture Correction</u>: If necessary, the owner or operator shall install a system to determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rules 62-4.070(3), 62-210.200(BACT), F.A.C]

45. <u>Ammonia Monitoring Requirements</u>: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system prior to the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with meeting the permitted NO_X limit for the combustion turbine load condition. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

46. CEMS Data Requirements for BACT Standards:

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition Nos. 15 - 24 of this section. These requirements cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs. Additional reporting and monitoring may be required by the individual subparts.}

a. *Data Collection*: Except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions shall be monitored and recorded during all operation including startup, shutdown, and malfunction.

b. *Operating Hours and Operating Days*: An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit. [Rule 62-4.070, F.A.C.]

c. *Valid Hour*: Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

   1) Hours that are **not operating** hours are **not valid** hours.
   2) For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid.
   3) During fuel switching an hour in which syngas is fired is attributed towards compliance with the permit standards for syngas firing.

d. *Rolling 24-Hour Average*: Compliance shall be determined after each valid hourly average is obtained by calculating the arithmetic average of that valid hourly average and the previous 23 valid hourly averages.

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO emissions depending on the use of alternate methods of operation}

e. *Rolling 30-day Average*: Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

f. *Rolling 12-month Total*: Compliance shall be determined after each calendar month by calculating the total emissions from that calendar month and the last 11 calendar months.

g. *Missing Data/Bias Adjustments*: If the owner or operator has installed a CEMS to meet the requirements of Part 75, data reported to show compliance with any SIP-based limit shall not include data substituted using the missing data procedures in Subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

h. *Data Exclusion*: Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, and fuel switches. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 36 and 37 of this subsection.

i. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]]

REPORTING AND RECORD KEEPING REQUIREMENTS

47. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and fuel switching). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

48. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

49. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur content. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

50. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

51. CEMS Data Assessment Report: The Data Assessment Report required by 40 CFR, Appendix F shall be submitted to the Compliance Authority on a quarterly basis for each CEMS required for compliance with a BACT limit only. Separate reporting may be required for CEMS installed for purposes of compliance with an NSPS limit, or Acid Rain.

52. Excess Emissions Reporting:

    a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO, and SO_2 emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. A summary of data excluded from SIP compliance calculations should also be provided. In addition, the report shall summarize the CO, NO_X, SO_2, and Hg CEMS systems monitor availability for the previous quarter.

c. *NSPS Reporting*: Within 30 days following each calendar quarter, the permittee shall submit the written reports required under 40 CFR 60.51Da for the previous quarter or semi-annual period to the Compliance Authority. Also, within 30 days following the end of each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions, as applicable, and defined by NSPS Da, and/or NSPS KKKK that occurred during the previous semi-annual period to the Compliance Authority.

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, 60.51Da and 60.4375]

53. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility in accordance with 62-210.370. Emissions reported for Unit B shall include estimates of emissions from the flare and startup stack. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

FEDERAL REQUIREMENTS

{Permitting Note: The following descriptions summarize specific regulations of the various subparts that are potentially applicable to Unit B. These summaries are based on the current status of each subpart and are included for purposes of clarification.}

54. NSPS Subpart Da: The provisions of Subpart Da apply to [illegible] recovery steam generators and the associated stationary combustion turbine(s) burning fuels containing 75 percent [illegible] (heat input) or more synthesis-coal gas on a 12-month rolling average. If Unit B burns 75 percent or more syngas on a 12-month rolling average, the CT/HRSG system will be subject to and must comply with the requirements of Subpart Da and not KKKK. Applicable requirements of Subpart Da are summarized below, and details of the Subpart can be found in Appendix [illegible] of this permit.

[illegible] Subpart Da Requirements					
Applicable [illegible] Firing ≥ 75 [illegible] Syngas (12-month Rolling average)					
Pollutant	Method of Operation	Limit Lb/mmBtu	Limit Lb/MWh	Averaging Time	Method of Compliance
[illegible]	All Modes	N/A	1.4	30-day Rolling	CEMS
NO_X	CT/CT & DB	N/A	1.0	30-day Rolling	CEMS
	DB	N/A	1.0	30-day Rolling	CEMS
PM	All Modes	0.015	0.14		CEMS[a]
		20% Opacity		6-minute block	Annual Test
Mercury	All Modes	N/A	0.000020	12-month Rolling	CEMS/Sorbent Trap

a. Demonstration of a fuel sulfur specification of ≤ 0.15 lb S/mmBtu fuel also demonstrates compliance with the PM limit for units that burn liquid or gaseous fuels.

[40 CFR 60 Subpart Da]

55. NSPS Subpart KKKK: The proposed provisions of Subpart KKKK apply to stationary gas turbines constructed after February 18, 2005. If Unit B burns less than 75 percent syngas on a 12-month rolling average, the CT/HRSG system will be subject to and must comply with the requirements of Subpart KKKK,

and not Subparts GG and Da. Applicable requirements of Subpart KKKK are summarized below, and details of the Subpart can be found in Appendix KKKK of this permit.

NSPS Subpart KKKK Requirements					
Applicable When Firing < 75% Syngas (12-month rolling average)					
Pollutant	Method of Operation	Limit		Averaging Time	Method of Compliance
		ppm @ 15% O_2	Or Lb/MWhr		
NO_X	CC	15	0.43	30-day Rolling	CEMS
	SC	15	0.43	4-hr Rolling	CEMS
SO_2	All modes	0.060 lb/mmBtu		Daily Sampling	Fuel Records
		Or 0.90 lb/MWh		Three 1-hr Runs	Annual Test

[40 CFR 60 Subpart KKKK]

56. NESHAP Subpart YYYY: The combustion turbine is subject to 40 CFR 63, Subpart A, Identification of General Provisions and 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. On August 18, 2004 EPA issued a final rule staying the effectiveness of this Subpart with respect to lean premix and diffusion flame gas-fired combustion turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 and comply with any other applicable requirement of Subpart YYYY upon final action by EPA and publication in the Federal Register. Subpart YYYY specifies an emission limit of 91 parts per billion (ppbv) of formaldehyde (CH_2O) applicable to stationary gas turbines.

[40 CFR 63 Subpart YYYY]

B. Unit B Flare (EU 031)

ID	Emission Unit Description
031	Unit B Flare – A multipoint flare (including 8 pilot flares) enclosed in a 20 foot thermal barrier fence used to combust syngas during startups (once the gasifier switches fuels from natural gas to coal), and during plant upset conditions.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). [Rule 62-210.200 (BACT), F.A.C.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one multipoint flare system, approximately 214 feet by 123 feet, enclosed in a 20 foot thermal barrier fence. The flare system will be designed to combust synthesis gas during startup, and during upsets of the gasification plant or the combustion turbine. The flare system will also include 8 pilot flares fueled by natural gas. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]
4. Authorized Fuels: Only natural gas containing no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas shall be fired in the pilot flares.
5. Methods of Operation: Subject to the restrictions and requirements of this permit, the flare may operate under the following methods of operation.
   a. *Pilot Flare*: The pilot flares shall be operated with a flame present at all times.
   b. *Synthesis Gas Flaring*: Once the gasifiers reach a reducing atmosphere, synthesis gas shall be directed through the gas clean-up processes to the flare. Flaring will take place only until there is sufficient synthesis gas production to support operation of the combustion turbine. Operation of the combustion turbine may be accomplished by mixing the synthesis gas with natural gas.

   [Application; Rules 62-210.200 (PTE, BACT) and 62-212.400 (PSD), F.A.C
6. Work Practice: Good combustion practices will be utilized at all times to ensure emissions from the flare system are minimized. The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of the flare and pilot systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]
7. Pilot Flares: The 8 pilot flares shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDS

8. Pilot Flare Records: The permittee shall keep readily accessible records demonstrating the presence of a flame on the pilot flares.

9. Fuel Records: The permittee shall keep records sufficient to determine the annual throughput of natural gas of this unit for use in the Annual Operating Report.
[Rule 62-204.800(7)(b)16, F.A.C]

C. Unit B Cooling Tower (EU 032)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
032	Unit B Cooling Tower – consisting of six cells with six individual exhaust fans.

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one 6-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 86,000 gpm; a design air flow rate of 1,361,880 acfm per cell; drift eliminators; and a drift rate of no more than 0.0005 percent of the circulating water flow. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing commercial operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-210.200(BACT), F.A.C.]

{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on these design criteria, potential emissions are estimated to be less than 14 tons of PM per year and less than 6 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}

D. Unit B Materials Storage and Handling (Units 33, 34, and 35)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description	
033	Unit B Coal Mill and Coal Storage – including coal crushing, and crushed coal storage, coal pulverizing and feed preparation.	
	Point ID No.	*Description*
	CMS1	Coal Mill Silo No. 1 Baghouse
	CMS2	Coal Mill Silo No. 2 Baghouse
	CMS3	Coal Mill Silo No. 3 Baghouse
	CMS4	Coal Mill Silo No. 4 Baghouse
	PCS1	Pulverized Coal Storage Bin No. 1 Baghouse
	PCS2	Pulverized Coal Storage Bin No. 2 Baghouse
	PCS3	Pulverized Coal Storage Bin No. 3 Baghouse
	PCS4	Pulverized Coal Storage Bin No. 4 Baghouse
034	Unit B Gasification Ash Storage – including fly ash storage silo and baghouse.	
035	Unit B Coal Handling – Including coal conveying and transfer.	

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: A determination of the Best Available Control Technology (BACT) was made for particulate matter (PM/PM10). To satisfy the BACT requirements for this unit the visible emissions limits, and the baghouse specifications are the surrogate standards for particulate matter. [Rule 62-210.200 (BACT), F.A.C.]

2. NSPS Requirements: These units are subject to 40 CFR 60, Subpart A (Identification of General Provisions) and 40 CFR 60, Subpart Y (Standards of Performance for Coal Preparation Plants). The Department determines that the BACT emissions performance requirements are as stringent as or more stringent than the limits imposed by the applicable NSPS provisions. Some separate reporting and monitoring may be required by the individual subparts.

EQUIPMENT AND CONTROL TECHNOLOGY

3. Equipment Description: The permittee is authorized to construct, operate, and maintain equipment needed for the grinding, storage, and handling of Unit B coal. Equipment will include a radial-pedestal stacker conveyor; a crushing shed with tramp screens, magnetic separator, sampling system, and crusher; four crushed coal silos with dedicated pulverizers; four surge bins; a high pressure coal feeder system; and all associated conveyor systems.

4. Baghouse Controls: Each coal mill silo and each pulverized coal storage bin will be controlled by a baghouse system. Each required baghouse shall be designed, operated, and maintained to achieve a PM design specification of 0.01 gr/dscf and a PM_{10} design specification of 0.0085 gr/dscf. [Rules 62-4.070(3), and 62-210.200 (BACT), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Hours of Operation: The hours of operation for this emissions unit are not limited (8760 hours per year). [Rule 62-21.200 (PTE), F.A.C.]

6. Unconfined Emissions of Particulate Matter

   a. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions. Such activities include, but are not limited to: vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling.

   b. Reasonable precautions shall include the following:

      (1) Landscaping and planting of vegetation.

      (2) Application of water to control fugitive dust from activities such as demolition of buildings, grading roads, construction, and land clearing.

      (3) Water supply lines, hoses and sprinklers shall be located near all stockpiles of raw materials, coal, and petroleum coke.

      (4) All plant operators shall be trained in basic environmental compliance and shall perform visual inspections of raw materials, coal and petroleum coke periodically and before handling. If the visual inspections indicate a lack of surface moisture, such materials shall be wetted with sprinklers. Wetting shall continue until the potential for unconfined particulate matter emissions are minimized.

      (5) Water spray shall be used to wet the materials and fuel if inherent moisture and moisture from wetting the storage piles are not sufficient to prevent unconfined particulate matter emissions.

      (6) As necessary, applications of asphalt, water, or dust suppressants to unpaved roads, yards, open stockpiles and similar activities.

      (7) Paving of access roadways, parking areas, manufacturing area, and fuel storage yard.

      (8) Removal of dust from buildings, roads, and other paved areas under the control of the owner or operator of the facility to prevent particulate matter from becoming airborne.

      (9) A vacuum sweeper shall be used to remove dust from paved roads, parking, and other work areas.

      (10) Enclosure or covering of conveyor systems where practicably feasible.

      (11) All materials at the plant shall be stored under roof. Materials, other than quarried materials, shall be stored in compacted clay or concrete or in enclosed vessels.

      (12) Use of hoods, fans, filters and similar equipment to contain, capture and/or vent particulate matter.

      (13) Confining abrasive blasting where possible.

   c. In determining what constitutes reasonable precautions for a particular source, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.

EMISSIONS AND TESTING REQUIREMENTS

7. Visible Emissions Standards: Visible emissions from each baghouse, and visible emissions from all coal processing and conveying equipment, coal storage systems, or coal transfer and loading systems and not controlled by a baghouse, shall not exceed 5 % opacity.

8. Testing Requirements: Each emission point shall be tested to demonstrate initial compliance with the visible emissions standards. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. Thereafter, compliance with the visible emission limits shall be demonstrated during each federal fiscal year (October 1st to September 30th). Compliance with the visible emission limits shall be determined by conducting EPA Method 9 tests. Tests shall be conducted in accordance with the applicable requirements in

Appendix C of this permit as well as the applicable NSPS provisions.
[Rule 62-297.310(7)(a), F.A.C., and 40 CFR 60.252]

9. Test Reports: For each test conducted, the permittee shall file a test report including the information specified in Rule 62-297.310(8), F.A.C. with the compliance authority no later than 45 days after the last run of each test is completed. [Rules 62-297.310(8), F.A.C.]

SECTION IV. APPENDICES

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SECTION IV. APPENDIX A

NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Insert Emissions Limits From Final Permit

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

P.E., Program Administrator
South Permitting Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
Trina L. Vielhauer, Chief Bureau of Air Regulation	Joseph Kahn, P.E., Acting Director Division of Air Resources Management
Date	Date

When burning 75 percent (by heat input) or more synthesis coal gas, on a 12-month rolling average, Unit B heat recovery steam generator and the associated stationary combustion turbine are subject to NSPS Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978).

{Permitting Note: Numbering of the original NSPS rules in the following conditions has been preserved for ease of reference. Paragraphs that are not applicable have been omitted for clarity and brevity. When used in 40 CFR 60, the term "Administrator" shall mean the Secretary or the Secretary's designee.}

§ 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) Heat recovery steam generators that are associated with stationary combustion turbines burning fuels other than 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. Heat recovery steam generators and the associated stationary combustion turbine(s) burning fuels containing 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average are subject to this part and are not subject to subpart KKKK of this part. This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the combined cycle gas turbine burn fuels other than synthetic-coal gas, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

[44 FR 33613, June 11, 1979, as amended at 63 FR 49453, Sept. 16, 1998. Redesignated at 70 FR 51268, Aug. 30, 2005, as amended at 71 FR 9876, Feb. 27, 2006]

§ 60.42Da Standard for particulate matter.

(b) On and after the date the particulate matter performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification is commenced after February 28, 2005, except for modified affected facilities meeting the requirements of paragraph (d) of this section, any gases that contain particulate matter in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under §60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel.

[44 FR 33613, June 11, 1979. Redesignated at 70 FR 51268, Aug. 30, 2005, as amended at 71 FR 9877, Feb. 27, 2006]

§ 60.43Da Standard for sulfur dioxide.

(i) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except as provided for under paragraphs (j) or (k) of this section, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6663, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 65 FR 61752, Oct. 17, 2000. Redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9877, Feb. 27, 2006]

§ 60.44Da Standard for nitrogen oxides.

(2) *NOx reduction requirement.*

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25
Liquid fuels	30
Solid fuels	65

(c) Except as provided under paragraph (d) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

En=[86 w+130×+210 y+260 z+340 v]/100

where:

En is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);

w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v is the percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(e) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an IGCC meeting the requirements of paragraph (f) of this section, any gases that contain nitrogen oxides (expressed as NO2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 63 FR 49453, Sept. 16, 1998; 66 FR 18551, Apr. 10, 2001; 66 FR 42610, Aug. 14, 2001. Redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9878, Feb. 27, 2006]

§ 60.45Da Standard for mercury.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction or reconstruction commenced after January 30, 2004, any gases which contain Hg emissions in excess of 20 × 10−6 lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average using the procedures in §60.50Da(g).

[70 FR 28653, May 18, 2005. Redesignated and amended at 70 FR 51268, Aug. 30, 2005]

§ 60.48Da Compliance provisions.

(a) Compliance with the particulate matter emission limitation under §60.42Da(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under §60.42Da(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under §60.44Da(a) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2).

(c) The particulate matter emission standards under §60.42Da, the nitrogen oxides emission standards under §60.44Da, and the Hg emission standards under §60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(e) After the initial performance test required under §60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under §60.43Da and the nitrogen oxides emission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under §60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under §60.43Da and the nitrogen oxides emission limitation under §60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average SO2 and NOX emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO2 and NOX for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NOX only), or emergency conditions (SO2) only.

(2) Compliance with applicable SO2 percentage reduction requirements is determined based on the average inlet and outlet SO2 emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.

(i) Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), or (f). The owner or operator of an affected facility subject to §60.44Da(d)(1) or (e)(1) shall calculate NOX emissions by multiplying the average hourly NOX output concentration, measured according to the provisions of §60.49Da(c), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and dividing by the average hourly gross energy output, measured according to the provisions of §60.49Da(k).

(k) Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1). To determine compliance with the emission limitation for NOX required by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NOX emission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NOX shall be computed using Equation 1 of this section:

$$E = [(Csg \times Qsg) - (Cte \times Qte)]/(Osg \times h) \quad \text{(Eq. 1)}$$

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

Csg = average hourly concentration of NOX exiting the steam generating unit, ng/dscm (lb/dscf)

Cte = average hourly concentration of NOX in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)

Qsg = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Qte = average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)

Osg = average hourly gross energy output from steam generating unit, J (Mwh)

h = average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

(ii) Method 7E of appendix A of this part shall be used to determine the NOX concentrations (Csg and Cte). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates (Qsg and Qte) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NOX emission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NOX emission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NOX shall be computed using Equation 2 of this section:

$$E = (Csg \times Qsd) / Occ \quad \text{(Eq. 2)}$$

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

Csg = average hourly concentration of NOX exiting the steam generating unit, ng/dscm (lb/dscf)

Qsg = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(ii) The continuous emissions monitoring system specified under §60.49Da for measuring NOX and oxygen shall be used to determine the average hourly NOX concentrations (Csg). The continuous flow monitoring system specified in §60.49Da(l) shall be used to determine the volumetric flow rate (Qsg) of the exhaust gas. The sampling site shall be located at the outlet from the steam generating unit. Data from a continuous flow monitoring system certified (or recertified) following procedures specified in 40 CFR 75.20, meeting the quality assurance and quality control requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (Occ), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/hr) of NOX emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of 40 CFR part 75. If this compliance option is selected, the emission rate (E) of NOX shall be computed using Equation 3 of this section:

$E = (ERsg \times Hcc) / Occ$ (Eq. 3)

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

ERsg = average hourly emission rate of NOX exiting the steam generating unit heat input calculated using appropriate F-factor as described in Method 19, ng/J (lb/million Btu)

Hcc = average hourly heat input rate of entire combined cycle unit, J/hr (million Btu/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(l) Compliance provisions for sources subject to §60.45Da. The owner or operator of an affected facility subject to §60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of §60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of §60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in §60.49Da(k). Compliance with the applicable standard under §60.45a is determined on a 12-month rolling average basis.

(m) Compliance provisions for sources subject to §60.43Da(i)(1)(i) or (j)(1)(i). The owner or operator of an affected facility subject to §60.43Da(i)(1)(i) or (j)(1)(i) shall calculate SO2 emissions by multiplying the average hourly SO2 output concentration, measured according to the provisions of §60.49Da(b), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k).

(n) Compliance provisions for sources subject to §60.42Da(c)(1). The owner or operator of an affected facility subject to §60.42Da(c)(1) shall calculate particulate matter emissions by multiplying the average hourly particulate matter output concentration, measured according to the provisions of §60.49Da(t), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) Compliance provisions for sources subject to §60.42Da(c)(2) or (d). Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) Conduct an initial performance test according to the requirements in §60.50Da to demonstrate compliance by the applicable date specified in §60.8(a) and, thereafter, conduct the performance test annually, and

(2) An owner or operator must use opacity monitoring equipment as an indicator of continuous particulate matter control device performance and demonstrate compliance with §60.42Da(b). In addition, baseline parameters shall be established as the highest hourly opacity average measured during the performance test. If any hourly average opacity measurement is more than 110 percent of the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test. The new baseline shall not exceed the opacity limit specified in §60.42Da(b), and

(3) An owner or operator using an ESP to comply with the applicable emission limits shall use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP. Baseline parameters shall be established as average rates measured during the performance test. If a 3-hour average voltage and secondary current average deviates more than 10 percent from the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test, and

(4) An owner or operator using a fabric filter to comply with the applicable emission limits shall install, calibrate, maintain, and continuously operate a bag leak detection system according to paragraphs (o)(4)(i) through (viii) of this section.

(i) Install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(ii) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(iii) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(iv) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(v) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(vi) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel. Corrective actions must be initiated within 1 hour of a bag leak detection system alarm. If the alarm is engaged for more than 5 percent of the total operating time on a 30-day rolling average, a performance test must be performed within 60 days to demonstrate compliance.

(vii) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(viii) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors, and

(5) An owner or operator of a modified affected source electing to meet the emission limitations in §60.42Da(d) shall determine the percent reduction in particulate matter by using the emission rate for particulate matter determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a continuous emission monitoring system measuring particulate matter emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a continuous monitoring system measuring particulate matter. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each continuous emission monitor shall be installed, certified, operated, and maintained according to the requirements in §60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19, section 4.1.

(5) At a minimum, valid continuous monitoring system hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/h, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(7) All valid continuous monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(5) of this section are not met.

(8) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 90 percent of all operating hours per 30-day rolling average.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 63 FR 49454, Sept. 16, 1998; 66 FR 18552, Apr. 10, 2001; 66 FR 31178, June 11, 2001. Redesignated and amended at 70 FR 28653, 28654, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9878, Feb. 27, 2006]

§ 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, 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, except where gaseous fuel is the only fuel combusted. 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 Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

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

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da(d), (i), (j), or (k) sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19may 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 under paragraph (b)(1) of this section.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51a shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator 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, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 shall be used to determine the SO2 concentration at the same location as the SO2 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.

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

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O2 or CO2 concentration at the same location as the O2 or CO2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (1b/million Btu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 shall be used to determine O2, SO2, and NOX concentrations, respectively.

(2) SO2 or NOX (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, 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)
Gas	500
Liquid	500
Solid.	1,000
Combination	500 (x+y)+1,000z

where:

x is the fraction of total heat input derived from gaseous fossil fuel,

y is the fraction of total heat input derived from liquid fossil fuel, and

z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) 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 of the fuel fired.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) 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 paragraph (i) of this section, the conditions under §60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) 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.

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

(4) For Method 3B, Method 3A may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under §60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under §60.42Da, §60.43Da, §60.44Da, or §60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B and procedure 1 of appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of 40 CFR part 75.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NOX standards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a continuous emissions monitoring system to measure NOX emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45Da shall install and operate a continuous emissions monitoring system (CEMS) to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (e.g., calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing record keeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da(c)(1) shall install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under §60.42Da(c)(2) may install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section in lieu of the requirements in §60.48Da(o).

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1) or (2) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in §60.48Da(o).

(1) A continuous monitoring system for measuring particulate matter emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under §60.42Da(a)(1) or §60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section.

(2) The affected source burns only oil that contains no more than 0.15 weight percent sulfur or liquid or gaseous fuels that when combusted without sulfur dioxide emission control, have a sulfur dioxide emissions rate equal to or less than or equal to 65 ng/J (0.15 lb/MMBtu) heat input.

(v) The owner or operator of an affected facility using a continuous emission monitoring system measuring particulate matter emissions to meet requirements of this subpart shall install, certify, operate, and maintain the continuous monitoring system as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the continuous monitoring system according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and conducting performance tests using the following test methods.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA Reference Method 3, 3A, or 3B, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990; 63 FR 49454, Sept. 16, 1998; 65 FR 61752, Oct. 17, 2000; 66 FR 18553, Apr. 10, 2001. Redesignated and amended at 70 FR 28653, 28654, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9880, Feb. 27, 2006]

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO2 and NOX. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.42Da as follows:

(1) The dry basis F factor (O2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particular matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

(i) 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).

(ii) 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 O2 concentration. The O2 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 O2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O2 traverse points. If the grab sampling procedure is used, the O2 concentration for the run shall be the arithmetic mean of the sample O2 concentrations at all traverse points.

(3) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO2 standards in §60.43Da as follows:

(1) The percent of potential SO2 emissions (%Ps) to the atmosphere shall be computed using the following equation:

%Ps=[(100—%Rf) (100—%Rg)]/100

where:

%Ps=percent of potential SO2 emissions, percent.

%Rf=percent reduction from fuel pretreatment, percent.

%Rg=percent reduction by SO2 control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction (%Rf) 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.

(3) The procedures in Method 19 shall be used to determine the percent SO2 reduction (%Rg) of any SO2 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 SO2 control device and the average SO2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in §60.49Da (b) and (d) shall be used to determine the concentrations of SO2 and CO2 or O2.

(d) The owner or operator shall determine compliance with the NOX standard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NOX.

(2) The continous monitoring system in §60.49Da (c) and (d) shall be used to determine the concentrations of NOX and CO2 or O2.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§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.

(2) The Fc factor (CO2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of §60.48(d)(1). The CO2 shall be determined in the same manner as the O2 concentration.

(f) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

(g) For the purposes of determining compliance with the emission limits in §§60.45Da and 60.46Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus half of the equivalent electrical energy in the unit's process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (i.e., 250 million Btu/hr input to an electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 million Btu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 1 of this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \quad \text{(Eq. 1)}$$

Where:

ERcogen = Cogeneration Hg emission rate over a compliance period in lb/MWh;

E = Mass of Hg emitted from the stack over the same compliance period (lb);

Vgrid = Amount of energy sent to the grid over the same compliance period (MWh); and

Vprocess = Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in §60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in §60.8(a). The required continuous monitoring systems must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the continuous monitoring systems for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial

performance test, the minimum data capture requirement in §60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in pounds (lb), using either Equation 2 in paragraph (h)(2)(i)(A) of this section or Equation 3 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 4 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 2 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K\,C_h Q_h t_h \qquad \text{(Eq. 2)}$$

Where:

Eh = Hg mass emissions for the hour, (lb)

K = Units conversion constant, 6.24 × 10− 11 lb-scm/μg-scf

Ch = Hourly Hg concentration, wet basis, (μg/scm)

Qh = Hourly stack gas volumetric flow rate, (scfh)

th = Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, th = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 3 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K\,C_h Q_h t_h \left(1 - B_{ws}\right) \qquad \text{(Eq. 3)}$$

Where:

Eh = Hg mass emissions for the hour, (lb)

K = Units conversion constant, 6.24 × 10− 11 lb-scm/μg-scf

Ch = Hourly Hg concentration, dry basis, (μg/dscm)

Qh = Hourly stack gas volumetric flow rate, (scfh)

th = Unit operating time, i.e., the fraction of the hour for which the unit operated

Bws = Stack gas moisture content, expressed as a decimal fraction (e.g., for 8 percent H2O, Bws = 0.08)

(C) Use Equation 4, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 2 or 3 (as applicable):

$$M = \sum_{h=1}^{n} E_h \qquad \text{(Eq. 4)}$$

Where:

M = Total Hg mass emissions for the month, (lb)

Eh = Hg mass emissions for hour "h", from Equation 2 or 3 of this section, (lb)

n = The number of unit operating hours in the month with valid CEM and electrical output data, excluding hours of unit startup, shutdown and malfunction

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 5, below. For a cogeneration unit, use Equation 1 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad \text{(Eq. 5)}$$

Where:

ER = Monthly Hg emission rate, (lb/MWh)

M = Total mass of Hg emissions for the month, from Equation 4, above, (lb)

P = Total electrical output for the month, for the hours used to calculate M, (MWh)

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 6 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=i}^{12} (ER)_i n_i}{\sum_{i=i}^{12} n_i} \qquad \text{(Eq. 6)}$$

Where:

Eavg = Weighted 12-month rolling average Hg emission rate, (lb/MWh)

(ER)i = Monthly Hg emission rate, for month "i", (lb/MWh)

n = The number of unit operating hours in month "i" with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in §75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 3 through 5 of this section, except that for a particular pair of sorbent traps, Ch in Equation 3 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride (Hg° or HgCl2) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using HgCl2 standards, as described in section 8.3 of Performance Specification 12–A in appendix B to this part (note: Hg° standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 65 FR 61752, Oct. 17, 2000. Redesignated and amended at 70 FR 28653, 28655, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9881, Feb. 27, 2006]

Editorial Note: At 70 FR 51269, Aug. 30, 2005, the Environmental Protection Agency published a document in the Federal Register, attempting to amend §60.50Da. However, because of inaccurate amendatory language, this amendment could not be incorporated. For the convenience of the user, the language at 70 FR 51269 is set forth as follows:

f. Revising the existing reference in paragraph (e)(2) from "§60.48a(d)(1)" to "§60.48Da(d)(1)";

§ 60.51Da Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) 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.

(4) 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 for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NOX only), emergency conditions (SO2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

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

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (ni) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (so) and inlet emission rates (si) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (Eo*) and the upper confidence limit for the mean inlet emission rate (Ei*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (Eo*) and the allowable emission rate (Estd) as applicable.

(d) If any standards under §60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under §60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

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

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

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 (appendix A); and

(2) 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.

(f) 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.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

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

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). 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.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO2 and/or NOX and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

[44 FR 33613, June 11, 1979, as amended at 63 FR 49454, Sept. 16, 1998; 64 FR 7464, Feb. 12, 1999. Redesignated and amended at 70 FR 28653, 28656, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005]

§ 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in §60.45Da or §60.46Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of §60.7(f).

[70 FR 28656, May 18, 2005. Redesignated and amended at 70 FR 51268, Aug. 30, 2005]

SECTION IV. APPENDIX GC

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emssion Standards for Hazardous Air Pollutants (X); and
    d. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

NSPS SUBPART KKKK REQUIREMENTS FOR STATIONARY COMBUSTION TURBINES

When burning less than 75 percent (by heat input) synthesis coal gas, on a 12-month rolling average, Unit B heat recovery steam generator and the associated stationary combustion turbine are subject to NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines).

Introduction

§ 60.4300 What is the purpose of this subpart?

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

Applicability

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

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

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

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

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

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

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

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

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NOX) and sulfur dioxide (SO2).

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

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

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

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

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

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

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

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

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

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

General Compliance Requirements

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

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

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

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

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

Monitoring

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

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

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

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NOX monitor and a diluent gas (oxygen (O2) or carbon dioxide (CO2)) monitor, to determine the hourly NOX emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

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

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

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

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

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

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

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

(2) Continuous parameter monitoring as follows:

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

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

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

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

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

If the option to use a NOX CEMS is chosen:

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

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

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

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

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

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

For purposes of identifying excess emissions:

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

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NOX and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOX emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O2 concentration exceeds 19.0 percent O2 (or the hourly average CO2 concentration is less than 1.0 percent CO2), a diluent cap value of 19.0 percent O2 or 1.0 percent CO2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NOX concentrations to 15 percent O2 is not allowed.

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

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

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

(1) For simple-cycle operation:

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

Where:

E = hourly NOX emission rate, in lb/MWh, (NOX)h = hourly NOX emission rate, in lb/MMBtu,

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

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

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

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

Where:

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

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

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

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

Where:

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

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 106 = conversion from Btu/h to MW.

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

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

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

Where:

E = NOX emission rate in lb/MWh,

(NOX)m = NOX emission rate in lb/h,

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for units located in continental areas and 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas or 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Reporting

§ 60.4375 What reports must I submit?

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

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

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

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

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

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

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

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

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

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NOX emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4- hour rolling average NOX emission rate" is the arithmetic average of the average NOX emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOX emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOX emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NOX emission rate" is the arithmetic average of all hourly NOX emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NOX emissions rates for the preceding 30 unit operating days if a valid NOX emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NOX concentration, CO2 or O2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

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

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

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

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

§ 60.4385 How are excess emissions and monitoring downtime defined for SO2?

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

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

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

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

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

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

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

§ 60.4395 When must I submit my reports?

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

Performance Tests

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

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

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

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

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

Where:

E = NOX emission rate, in lb/MWh

1.194 × 10–7 = conversion constant, in lb/dscf-ppm

(NOX)c = average NOX concentration for the run, in ppm

Qstd = stack gas volumetric flow rate, in dscf/hr

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

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

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

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

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

(A) [Reserved], or

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

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

(A) If each of the individual traverse point NOX concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO2 (or O2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NOX concentration during the stratification test; or

(B) For turbines with a NOX standard greater than 15 ppm @ 15% O2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOX concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO2 (or O2) from the mean for all traverse points; or

(C) For turbines with a NOX standard less than or equal to 15 ppm @ 15% O2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOX concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO2 (or O2) from the mean for all traverse points.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

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

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

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

(2) Measure the SO2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO2 emission rate:

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

Where:

E = SO2 emission rate, in lb/MWh

1.664 × 10−7 = conversion constant, in lb/dscf-ppm

(SO2)c = average SO2 concentration for the run, in ppm

Qstd = stack gas volumetric flow rate, in dscf/hr

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

(3) Measure the SO2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO2 emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

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

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

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

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

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

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

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

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

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

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation. *ISO conditions* means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

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

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

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

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

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

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

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

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

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

Table 1_to Subpart KKKK of Part 60_Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOX emission standard
New turbine firing natural gas, electric generating	[le] 50 MMBtu/h...	42 ppm at 15. percent O2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive.	[le] 50 MMBtu/h...	100 ppm at 15 percent O2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h	25 ppm at 15 percent O2 or 150 ng/J of useful output (1.2 lb/ MWh).
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h...	15 ppm at 15 percent O2 or 54 ng/J of useful output (0.43 lb/ MWh)
New turbine firing fuels other than natural gas, electric generating	[le] 50 MMBtu/h...	96 ppm at 15 percent O2 or 700 . ng/J of useful output (5.5 lb/ MWh).
New turbine firing fuels other than natural gas, mechanical drive.	[le] 50 MMBtu/h...	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and [le] 850 MMBtu/h	74 ppm at 15 percent O2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 850 MMBtu/h...	42 ppm at 15 percent O2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine.	[le] 50 MMBtu/h...	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h.	42 ppm at 15 percent O2 or 250 ng/J of useful output (2.0 lb/ MWh).
Modified or reconstructed turbine firing fuels other than natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h	96 ppm at 15 percent O2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F.	[le] 30 MW output.	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	> 30 MW output.	96 ppm at 15 percent O2 or 590 ng/J of useful 75 output (4.7 lb/ MWh).
Heat recovery units operating independent of the combustion turbine.	All sizes.........	54 ppm at 15 percent O2 or 110 ng/J of useful output (0.86 lb/MWh).

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

    b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

    [Rule 62-297.310(4), F.A.C.]

14. Determination of Process Variables

    a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

    [Rule 62-297.310(5), F.A.C.]

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1) The type, location, and designation of the emissions unit tested.
2) The facility at which the emissions unit is located.
3) The owner or operator of the emissions unit.
4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8) The date, starting time and duration of each sampling run.
9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10) The number of points sampled and configuration and location of the sampling plane.
11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12) The type, manufacturer and configuration of the sampling equipment used.
13) Data related to the required calibration of the test equipment.
14) Data on the identification, processing and weights of all filters used.
15) Data on the types and amounts of any chemical solutions used.
16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18) All measured and calculated data required to be determined by each applicable test procedure for each run.
19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
20) The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A

NSPS SUBPART Y REQUIREMENTS FOR COAL PREPARATION PLANTS

The specific conditions of this subsection apply to the following emissions units.

ID	Emission Unit Description
033	Unit B Coal Mill and Coal Storage – including coal crushing, and crushed coal storage, coal pulverizing and feed preparation.
034	Unit B Gasification Ash Storage – including fly ash storage silo and baghouse.
035	Unit B Coal Handling – Including coal conveying and transfer.

1. NSPS Subpart A: The affected emissions units are also subject to the applicable General Provisions in Subpart A of 40 CFR 60, as adopted by Rule 62-204.800(8), F.A.C. [40 CFR 60, Subpart A]
2. NSPS Subpart Y: The affected emissions units are also subject to the applicable requirements for Coal Preparation Plants specified in NSPS Subpart Y of 40 CFR 60, as adopted by Rule 62-204.800(8), F.A.C. [40 CFR 60, Subpart Y]

{Permitting Note: Numbering of the original NSPS rules in the following conditions has been preserved for ease of reference with the rules. Paragraphs that are not applicable have been omitted for clarity and brevity. When used in 40 CFR 60, the term "Administrator" shall mean the Secretary or the Secretary's designee.}

§ 60.250 Applicability and Designation of Affected Facility.

(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 200 tons per day: thermal dryers, pneumatic coal cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems.

§ 60.251 Definitions.

(a) *Coal preparation plant* means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(b) Bituminous coal means solid fossil fuel classified as bituminous coal by ASTM Designation D388-77, 90, 91, 95, or 98a (incorporated by reference; see § 60.17).

(c) Coal means all solid fossil fuels classified as anthracite, bituminous, sub bituminous, or lignite by ASTM Designation D388-77, 90, 91, 95, or 98a (incorporated by reference; see § 60.17).

(d) Cyclonic flow means a spiraling movement of exhaust gases within a duct or stack.

(e) Thermal dryer means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(f) Pneumatic coal-cleaning equipment means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(g) Coal processing and conveying equipment means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

(h) Coal storage system means any facility used to store coal except for open storage piles.

(i) Transfer and loading system means any facility used to transfer and load coal for shipment.

§ 60.252 Standards for Particulate Matter.

(a) On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, an owner or operator shall not cause to be discharged into the atmosphere from any thermal dryer gases which:

(1) Contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(c) On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, an owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment or coal storage system, gases which exhibit 20 percent opacity or greater. [40 CFR 60.252(a) and (c)].

60.253 Monitoring of operations.

(a) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±1.7 °C (±3 °F).

(2) For affected facilities that use venturi scrubber emission control equipment:

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(ii) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations.

(b) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under §60.13(b).

[41 FR 2234, Jan. 15, 1976, as amended at 54 FR 6671, Feb. 14, 1989; 65 FR 61757, Oct. 17, 2000]

§ 60.254 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the particular matter standards in §60.252 as follows:

(1) Method 5 shall be used to determine the particulate matter concentration. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin.

(2) Method 9 and the procedures in §60.11 shall be used to determine opacity.

[54 FR 6671, Feb. 14, 1989]

NESHAP SUBPART YYYY HAP STANDARDS FOR STATIONARY COMBUSTION TURBINES

The Unit B combustion turbine is subject to 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines

{Permitting Note: Numbering of the original NESHAP rules in the following conditions has been preserved for ease of reference. Paragraphs that are not applicable have been omitted for clarity and brevity.}

§ 63.6085 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.

(a) Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to this subpart do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

(b) A major source of HAP emissions is a contiguous site under common control that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

§ 63.6090 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) Affected source. An affected source is any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions.

(2) New stationary combustion turbine. A stationary combustion turbine is new if you commenced construction of the stationary combustion turbine after January 14, 2003.

§ 63.6095 When do I have to comply with this subpart?

(c) You must meet the notification requirements in §63.6145 according to the schedule in §63.6145 and in 40 CFR part 63, subpart A.

(d) Stay of standards for gas-fired subcategories. If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

[69 FR 10537, Mar. 5, 2004, as amended at 69 FR 51188, Aug. 18, 2004]

Emission and Operating Limitations

§ 63.6100 What emission and operating limitations must I meet?

For each new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart, you must comply with the emission limitations and operating limitations in Table 1 and Table 2 of this subpart.

General Compliance Requirements

§ 63.6105 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations which apply to you at all times except during startup, shutdown, and malfunctions.

(b) If you must comply with emission and operating limitations, you must operate and maintain your stationary combustion turbine, oxidation catalyst emission control device or other air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

Testing and Initial Compliance Requirements

§ 63.6110 By what date must I conduct the initial performance tests or other initial compliance demonstrations?

(a) You must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of this subpart that apply to you within 180 calendar days after the compliance date that is specified for your stationary combustion turbine in §63.6095 and according to the provisions in §63.7(a)(2).

§ 63.6115 When must I conduct subsequent performance tests?

Subsequent performance tests must be performed on an annual basis as specified in Table 3 of this subpart.

§ 63.6120 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Table 3 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements of the General Provisions at §63.7(e)(1) and under the specific conditions in Table 2 of this subpart.

(c) Do not conduct performance tests or compliance evaluations during periods of startup, shutdown, or malfunction. Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent.

(d) You must conduct three separate test runs for each performance test, and each test run must last at least 1 hour.

(e) If your stationary combustion turbine is not equipped with an oxidation catalyst, you must petition the Administrator for operating limitations that you will monitor to demonstrate compliance with the formaldehyde emission limitation in Table 1. You must measure these operating parameters during the initial performance test and continuously monitor thereafter. Alternatively, you may petition the Administrator for approval of no additional operating limitations. If you submit a petition under this section, you must not conduct the initial performance test until after the petition has been approved or disapproved by the Administrator.

(f) If your stationary combustion turbine is not equipped with an oxidation catalyst and you petition the Administrator for approval of additional operating limitations to demonstrate compliance with the formaldehyde emission limitation in Table 1, your petition must include the following information described in paragraphs (f)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as additional operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(g) If you petition the Administrator for approval of no additional operating limitations, your petition must include the information described in paragraphs (g)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary combustion turbine and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of why establishing limitations on the parameters is not possible;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of why you could not establish upper and/or lower values for the parameters which would establish limits on the parameters as operating limitations;

(5) For the parameters which could change in such a way as to increase HAP emissions, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible, unreasonable or unnecessary to adopt the parameters as operating limitations.

§ 63.6125 What are my monitor installation, operation, and maintenance requirements?

(a) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you use an oxidation catalyst emission control device, you must monitor on a continuous basis your catalyst inlet temperature in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(b) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you are not using an oxidation catalyst, you must continuously monitor any parameters specified in your approved petition to the Administrator, in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(d) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must monitor and record your distillate oil usage daily for all new and existing stationary combustion turbines located at the major source with a non-resettable hour meter to measure the number of hours that distillate oil is fired.

§ 63.6130 How do I demonstrate initial compliance with the emission and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 4 of this subpart.

(b) You must submit the Notification of Compliance Status containing results of the initial compliance demonstration according to the requirements in §63.6145(f).

Continuous Compliance Requirements

§ 63.6135 How do I monitor and collect data to demonstrate continuous compliance?

(a) Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), you must conduct all parametric monitoring at all times the stationary combustion turbine is operating.

(b) Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. You must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.

§ 63.6140 How do I demonstrate continuous compliance with the emission and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Table 1 and Table 2 of this subpart according to methods specified in Table 5 of this subpart.

(b) You must report each instance in which you did not meet each emission imitation or operating limitation. You must also report each instance in which you did not meet the requirements in Table 7 of this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6150.

(c) Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, and malfunction are not violations if you have operated your stationary combustion turbine in accordance with §63.6(e)(1)(i).

[69 FR 10537, Mar. 5, 2004, as amended at 71 FR 20467, Apr. 20, 2006]

Notifications, Reports, and Records

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(c) As specified in §63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with §63.6090(b), your notification must include the information in §63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in §63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

§ 63.6150 What reports must I submit and when?

(a) Anyone who owns or operates a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of this subpart. The semiannual compliance report must contain the information described in paragraphs (a)(1) through (a)(4) of this section. The semiannual compliance report must be submitted by the dates specified in paragraphs (b)(1) through (b)(5) of this section, unless the Administrator has approved a different schedule.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) For each deviation from an emission limitation, the compliance report must contain the information in paragraphs (a)(4)(i) through (a)(4)(iii) of this section.

(i) The total operating time of each stationary combustion turbine during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(iii) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(b) Dates of submittal for the semiannual compliance report are provided in (b)(1) through (b)(5) of this section.

(1) The first semiannual compliance report must cover the period beginning on the compliance date specified in §63.6095 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date specified in §63.6095.

(2) The first semiannual compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified in §63.6095.

(3) Each subsequent semiannual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent semiannual compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) If you are operating as a stationary combustion turbine which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (c)(1) through (c)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas, digester gas, or gasified MSW is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(d) Dates of submittal for the annual report are provided in (d)(1) through (d)(5) of this section.

(1) The first annual report must cover the period beginning on the compliance date specified in §63.6095 and ending on December 31.

(2) The first annual report must be postmarked or delivered no later than January 31.

(3) Each subsequent annual report must cover the annual reporting period from January 1 through December 31.

(4) Each subsequent annual report must be postmarked or delivered no later than January 31.

(5) For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (d)(1) through (4) of this section.

(e) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (e)(1) through (e)(3) of this section.

(1) The number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

§ 63.6155 What records must I keep?

(a) You must keep the records as described in paragraphs (a)(1) through (5).

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(3) Records of the occurrence and duration of each startup, shutdown, or malfunction as required in §63.10(b)(2)(i).

(4) Records of the occurrence and duration of each malfunction of the air pollution control equipment, if applicable, as required in §63.10(b)(2)(ii).

(5) Records of all maintenance on the air pollution control equipment as required in §63.10(b)(iii).

(b) If you are operating a stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis, or if you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must keep the records of your daily fuel usage monitors.

(c) You must keep the records required in Table 5 of this subpart to show continuous compliance with each operating limitation that applies to you.

§ 63.6160 In what form and how long must I keep my records?

(a) You must maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must retain your records of the most recent 2 years on site or your records must be accessible on site. Your records of the remaining 3 years may be retained off site.

Table 1 to Subpart YYYY of Part 63—Emission Limitations

For each new or reconstructed stationary combustion turbine described in §63.6100 which is:	You must meet the following emission limitations:
1. a lean premix gas-fired stationary combustion turbine as defined in this subpart,	limit the concentration of formaldehyde to 91 ppbvd or less at 15 percent O2.
2. a lean premix oil-fired stationary combustion turbine as defined in this subpart,	
3. a diffusion flame gas-fired stationary combustion turbine as defined in this subpart, or	
4. a diffusion flame oil-fired stationary combustion turbine as defined in this subpart	

Table 2 to Subpart YYYY of Part 63—Operating Limitations

For:	You must:
1. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst.	maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer.
2. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is not using an oxidation catalyst.	maintain any operating limitations approved by the Administrator.

Table 3 to Subpart YYYY of Part 63—Requirements for Performance Tests and Initial Compliance Demonstrations

You must:	Using:	According to the following requirements:
a. demonstrate formaldehyde emissions meet the emission limitations specified in Table 1 by a performance test initially and on annual basis AND.	Test Method 320 of 40 CFR part 63, appendix A; ASTM D6348-03 provided an that %R as determined in Annex A5 of ASTM D6348-03 is equal or greater than 70% and less than or equal to 130%; or other methods approved by the Administrator.	Formaldehyde concentration must be corrected to 15 percent O2, dry basis. Results of this test consist of the average of the three 1 hour runs. Test must be conducted within 10 percent of 100 percent load.
b. select the sampling port location and the number of traverse points AND…	Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	if using an air pollution control device, the sampling site must be located at the outlet of the air pollution control device.
c. determine the O2 concentration at the sampling port location AND…	Method 3A or 3B of 40 CFR part 60, appendix A.	measurements to determine O2 concentration must be made at the same time as the performance test.
d. determine the moisture content at the sampling port location for the purposes of correcting the	Method 4 of 40 CFR part 60, appendix A or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.	measurements to determine moisture content must be made at the same time as the performance test.

formaldehyde concentration to a dry basis.	

Table 5 to Subpart YYYY of Part 63—Continuous Compliance With Operating Limitations

For each stationary combustion turbine complying with the emission limitation for formaldehyde	You must demonstrate continuous compliance by
1. with an oxidation catalyst	continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer.
2. without the use of an oxidation catalyst	continuously monitoring the operating limitations that have been approved in your petition to the Administrator.

Table 6 to Subpart YYYY of Part 63—Requirements for Reports

If you own or operate a	you must	According to the following requirements
1. stationary combustion turbine which must comply with the formaldehyde emission limitation.	report your compliance status	semiannually, according to the requirements of § 63.6150.
2. stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis	report (1) the fuel flow rate of each fuel and heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas, digester gas, or gasified MSW is equivalent to 10 percent or more of the gross heat input on an annual basis, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters.	annually, according to the requirements in § 63.6150.
3. a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source.	report (1) the number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters.	annually, according to the requirements in § 63.6150