Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

April 20, 1999

Mr. Robert F. Hicks
Director, Environmental Division
Orlando Utilities Commission
500 So. Orange Avenue
Orlando, Florida 32801

Re: PROPOSED Title V Permit No.: 0950137-001-AV
Curtis H. Stanton Energy Center

Dear Mr. Hicks:

One copy of the "PROPOSED PERMIT DETERMINATION" for the Curtis H. Stanton Energy Center located at 5100 Alafaya Trail, Orlando, Orange County, is enclosed. This letter is only a courtesy to inform you that the DRAFT permit has become a PROPOSED permit.

An electronic version of this determination has been posted on the Division of Air Resources Management's world wide web site for the United States Environmental Protection Agency (USEPA) Region 4 office's review. The web site address is *http://www2.dep.state.fl.us/air*.

Pursuant to Section 403.0872(6), Florida Statutes, if no objection to the PROPOSED permit is made by the USEPA within 45 days, the PROPOSED permit will become a FINAL permit no later than 55 days after the date on which the PROPOSED permit was mailed (posted) to USEPA. If USEPA has an objection to the PROPOSED permit, the FINAL permit will not be issued until the permitting authority receives written notice that the objection is resolved or withdrawn.

If you should have any questions, please contact Michael P. Halpin, P.E. at 850/921-9530.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/h

Enclosures

copy furnished to:
Mr. Len Kozlov, CD
Ms. Gracy R. Danois, USEPA, Region 4 (INTERNET E-mail Memorandum)
Ms. Carla E. Pierce, USEPA, Region 4 (INTERNET E-mail Memorandum)

4/26/99 cc - Reading File
Mike Halpin

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

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's A
2. ☐ Restricted Deli

Consult postmaster for

Is your **RETURN ADDRESS** completed on the reverse side?

3. Article Addressed to:

Mr. Robert F. Hicks
Director, Environmental Division
Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801

4a. Article Number
P 263 585 208

4b. Service Type
☐ Registered ☒ C
☐ Express Mail ☐ I
☐ Return Receipt for Merchandise ☐ C

7. Date of Delivery

ORLANDO FL DOWNTOWN
29
1999
USPS

5. Received By: *(Print Name)*

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

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

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

PS Form **3800**, April 1995

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

P 263 585 208

Sent to	Mr. Robert Hicks
Street & Number	500 South Orange Avenue
Post Office, State, & ZIP Code	Orlando, FL 32801
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	4/26/99 OUC - Curtis H. Stanton Facility ID #0950137-001-AV

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

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Add
2. ☐ Restricted Delive

Consult postmaster for fe

Is your RETURN ADDRESS completed on the reverse side?

3. Article Addressed to:

Mr. Len Kozlov
Florida Department of Environ-
mental Protection
3319 Maguire Boulevard
Suite 232
Orlando, Florida 32803-3767

4a. Article Number
P 263 585 209

4b. Service Type
☐ Registered ☒ Ce
☐ Express Mail ☐ Ins
☐ Return Receipt for Merchandise ☐ CO

7. Date of Delivery

5. Received By: *(Print Name)*

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

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

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

PS Form **3800**, April 1995

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

P 263 585 209

Sent to	Mr. Len Kozlov
Street & Number	3319 Maguire Boulevard
Post Office, State, & ZIP Code	Orlando, FL 32803-3767
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	4/26/99 OUC - Curtis H. Stanton Facility ID# 0950137-001-AV

PROPOSED PERMIT DETERMINATION

I. Public Notice.

An "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" to Orlando Utilities Commission for the Curtis H. Stanton Energy Center located at 5100 Alafaya Trail, Orlando, Orange County was clerked on October 7, 1998. The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was published in the Orlando Sentinel on December 15, 1998. The DRAFT Title V Air Operation Permit was available for public inspection at the permitting authority's office in Orlando. Proof of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was received on December 21, 1998.

II. Public Comment(s).

A. The only comments received were from Orlando Utilities Commission in a letter from Mr. Robert F. Hicks dated January 25, 1999 and received on January 27, 1999. This letter is on file with the permitting authority. All comments were considered to be acceptable and are incorporated as follows:

1. Comment on page 2, Subsection A, nameplate rating:

As a result of this comment, Subsection A is hereby changed:

From:
Unit No. 1 consists of a Babcock and Wilcox boiler/steam generator (Model RB 611) and steam turbine, which drives a generator with a nameplate rating of 460 Megawatts. Unit No. 2 consists of a Babcock and Wilcox boiler/steam generator (Model RB 621) and steam turbine, which drives a generator with a nameplate rating of 465 Megawatts.

To:
Unit No. 1 consists of a Babcock and Wilcox boiler/steam generator (Model RB 611) and steam turbine, which drives a generator with a nameplate rating of 468 Megawatts. Unit No. 2 consists of a Babcock and Wilcox boiler/steam generator (Model RB 621) and steam turbine, which drives a generator with a nameplate rating of 468 Megawatts.

2. Comment on Page 6, Section III - Subsection A, nameplate ratings and maximum heat input :

As a result of this comment, Section III - Subsection A is hereby changed:

From:
Fossil fuel fired steam generator # 1 is a nominal 460 megawatt steam generator designated as Unit # 1. The emission unit is fired primarily on bituminous coal and secondarily on No. 6 fuel oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4136 MMBtu per hour.

Fossil fuel fired steam generator # 2 is a nominal 465 megawatt steam generator designated as Unit # 2. The emission unit is fired primarily on bituminous coal and secondarily on No. 6 fuel oil and on-specification used oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

To:
Fossil fuel fired steam generator # 1 is a nominal 468 megawatt steam generator designated as Unit # 1. The emission unit is fired primarily on bituminous coal and secondarily on No. 6 fuel oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

Fossil fuel fired steam generator # 2 is a nominal 468 megawatt steam generator designated as Unit # 2. The emission unit is fired primarily on bituminous coal and secondarily on No. 6 fuel oil and on-specification used oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

Note: Table 1-1 has been revised to reflect the corrected "equivalent emissions".

3. Comment on Page 8, Condition A.9.:

As a result of this comment, Condition A.9. is hereby changed:

From:
A.9. Sulfur dioxide emissions from Unit No. 1 when combusting solid fuel shall not exceed 1.14 lb/million Btu (3-hr average) heat input (4715 lbs/hr and 20,652 tons/year) and 10 percent of the potential combustion concentration (90 percent reduction) or 30 percent of the potential combustion concentration (70 percent reduction) when emissions are less than 0.60 lb/million Btu heat input. [Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(a)(1) and (2); PSD-FL-084]

To:
A.9. Sulfur dioxide emissions from Unit No. 1 when combusting solid fuel shall not exceed 1.2 lb/million Btu (30 day rolling average) heat input or 1.2 lb/million Btu (2 hour emission rate) heat input. Additionally, sulfur dioxide emissions from Unit No. 1 when combusting solid fuel shall not exceed 1.14 lb/million Btu (3-hr average) heat input (4886 lbs/hr and 21,400 tons/year) and 10 percent of the potential combustion concentration (90 percent reduction) or 30 percent of the potential combustion concentration (70 percent reduction) when emissions are less than 0.60 lb/million Btu heat input. [Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(a)(1) and (2); PSD-FL-084]

4. Comment on Page 20, Condition B.3.:

Since the condition is acceptable as written, no changes will result.

5. Comment on Table 2-1:

As a result of this comment, Table 2-1 is changed to reflect no CMS for particulate.

The enclosed PROPOSED Title V Air Operation Permit includes the aforementioned changes to the DRAFT Title V Air Operation Permit.

III. Conclusion.

The permitting authority hereby issues the PROPOSED Permit No.: 0950137-001-AV, with changes noted above.

STATEMENT OF BASIS

Orlando Utilities Commission
Curtis H. Stanton Energy Center
Facility ID No.: 0950137
Orange County

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0950137-001-AV

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

This facility consists of two fossil fuel fired steam electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2); solid fuels, fly ash, limestone, gypsum, slag, and bottom ash storage and handling facilities. Unit No. 1 consists of a Babcock and Wilcox boiler/steam generator (Model RB 611) and steam turbine which drives a generator with a nameplate rating of 468 Megawatts. Unit No. 2 consists of a Babcock and Wilcox boiler/steam generator (Model RB 621) and steam turbine which drives a generator with a nameplate rating of 468 Megawatts. Each boiler/steam generator is a wall fired dry bottom unit. Unit Nos. 1 and 2 are fired with coal, with No. 6 fuel oil used for startup and flame stabilization. Each unit has their individual stacks. An auxiliary boiler which serves both boilers and has a maximum heat input of 83 MMBtu/hour is located at the facility. The auxiliary boiler is fired with No. 2 distillate fuel oil.

Fossil fuel fired steam generator # 1 is a nominal 468 megawatt steam generator designated as Unit # 1. The emission unit is fired primarily on bituminous coal and secondarily on No. 6 fuel oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

Fossil fuel fired steam generator # 2 is a nominal 468 megawatt steam generator designated as Unit # 2. The emission unit is fired primarily on bituminous coal and secondarily on No. 6 fuel oil and on-specification used oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

Each boiler/steam generator, units #1 and #2, drives a turbine generator and both units have an individual 550 foot exhaust stack. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Wheelabrator-Frye Inc. The control efficiency of the ESP is 99.7%. Sulfur dioxide emissions are controlled by flue gas desulfurization equipment manufactured by Combustion Engineering.

Each boiler/steam generator, units #1 and #2 are regulated under the federal Acid Rain Program, Phase I and Phase II, adopted and incorporated by reference in Rule 62-204.800, F.A.C.; and NSPS-40 CFR 60, Subpart Da, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT). Fossil fuel fired steam generator # 1 began commercial operation on May 12, 1987; and, fossil fuel fired steam generator # 2 began commercial operation on March 29, 1996.

The auxiliary boiler is designated as Unit No. 3. The unit is a Babcock & Wilcox Model No. FM-2919 boiler. It is fired primarily with "new oil", which means an oil which has been refined from crude oil and has not been used. Only No. 2 fuel oil can be burned in the auxiliary boiler. This auxiliary boiler serves both Unit No. 1 and 2 boiler/steam generators. The emission unit is regulated under Rule 62-210.300, F.A.C., Permits Required.

Fly Ash Silos No. 1 and No. 2 handle fly ash from Steam Generators No. 1 and No. 2 respectively. Fly ash is pneumatically conveyed from the individual electrostatic precipitators to Silos No. 1 and No. 2 and then is gravity fed by tubing into totally enclosed tanker trucks. Particulate matter emissions generated by silo loading and unloading to a tanker truck is controlled by baghouses in addition to reasonable precautions. The emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required.

The heat input limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 95 to 100 percent of the emissions unit's rated capacity (or to limit future operation to 105 percent of the test load), to establish appropriate emissions limits and to aid in determining future rule applicability. A note below the permitted capacity condition clarifies this. Regular record keeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required to demonstrate at what percentage of the rated capacity that the emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of process variables for emissions tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the initial Title V permit application received June 17, 1996, this facility is not a major source of hazardous air pollutants (HAPs).

Orlando Utilities Commission
Curtis H. Stanton Energy Center

Facility ID No.: 0950137
Orange County

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0950137-001-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-1344
Fax: 850/922-6979

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0950137-001-AV

Table of Contents

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

Permittee:
Orlando Utilities Commission

PROPOSED Permit No.: 0950137-001-AV
Facility ID No.: 0950137
SIC Nos.: 4911
Project: Initial Title V Air Operation Permit

This permit is for the operation of the Stanton Energy Center. This facility is located at 5100 Alafaya Trail, Orlando, Orange County; UTM Coordinates: Zone 17, 484.00km East and 3150.50 km North; Latitude: 28° 28' 50" North and Longitude: 81° 09' 40" West.

STATEMENT OF BASIS: This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
APPENDIX TV-1, TITLE V CONDITIONS (version dated 12/02/97)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE
SUMMARY REPORT- GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE REPORT (40 CFR 60, July 1996)

Effective Date: January 1, 2000
Renewal Application Due Date: July 5, 2004
Expiration Date: December 31, 2004

Howard L. Rhodes, Director
Division of Air Resource
Management

HLR/sms/mh

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of two fossil fuel fired steam electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2); also, there are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash. Unit No. 1 consists of a Babcock and Wilcox boiler/steam generator (Model RB 611) and steam turbine, which drives a generator with a nameplate rating of 468 Megawatts. Unit No. 2 consists of a Babcock and Wilcox boiler/steam generator (Model RB 621) and steam turbine, which drives a generator with a nameplate rating of 468 Megawatts. Each boiler/steam generator is a wall fired dry bottom unit. Unit Nos. 1 and 2 are fired with coal, with No. 6 fuel oil used for startup and flame stabilization. Each unit has their individual stacks. An auxiliary boiler, which serves both boilers and with a maximum heat input of 83 MMBtu/hour, is located at the facility. The auxiliary boiler is fired with No. 2 distillate fuel oil.

Also included in this permit are miscellaneous unregulated emissions units and insignificant emissions units and/or activities.

Based on the initial Title V permit application received on June 17, 1996, this facility is not a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Electric Generator No. 1
-002	Fossil Fuel Fired Steam Electric Generator No. 2
-003	Auxiliary Boiler
-004	Coal Transfer Baghouse
-005	Coal Crusher Building Baghouse
-006	Coal Plant Transfer and Silo Fill Area #1 Baghouse
-007	Coal Plant Transfer and Silo Fill Area #2 Baghouse
-008	Limestone Day Bin Baghouse
-009	Pebble Lime Receiving Hopper Baghouse
-010	Coal Reclaim Hopper Baghouse
-011	Flyash Exhauster Filter #1 Baghouse
-012	Flyash Exhauster Filter #2 Baghouse
-013	Flyash Exhauster Filter #3 Baghouse
-014	Flyash Exhauster Filter #4 Baghouse
-015	Flyash Silo Bin Vent Filter Baghouse
-016	Adipic Acid Storage Baghouse

Unregulated Emissions Units and/or Activities

-xxx Material Handling
-xxx Fuel Storage Tanks
-xxx Water Treatment
-xxx Unconfined emissions

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:

Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes

These documents are on file with the permitting authority:

Phase II Acid Rain Application/Compliance Plan received December 14, 1995
Initial Title V Permit Application received June 17,1996.
Phase II NO_x Acid Rain Application/Compliance Plan Received January 5, 1998.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-1, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-1, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)1. & 4., F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA). If required by 40 CFR 68, the permittee shall submit to the implementing agency:
a. a risk management plan (RMP) when, and if, such requirement becomes applicable; and
b. certification forms and/or RMPs according to the promulgated rule schedule.
[40 CFR 68]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

7. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents Emissions. The permittee shall allow no person to 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)(a), F.A.C.]

8. Not federally enforceable. The following reasonable precautions shall be taken to prevent emissions of unconfined particulate matter at this facility.

- Maintenance of paved areas as needed,
- Regular mowing of grass and care of vegetation,
- Limiting access to plant property by unnecessary vehicles, and
- Additional or alternative activities may be utilized to minimize unconfined particulate emissions.

[Rule 62-296.320(4)(c)2., F.A.C.; and, proposed by applicant in the initial Title V permit application received June 14, 1996.]

9. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.
[Rule 62-213.440, F.A.C.]

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year.
{See condition 52., APPENDIX TV-1, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

11. The permittee shall submit all compliance-related notifications and reports required of this permit to the Central District Office:

Department of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

12. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9055, Fax: 404/562-9164

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following Regulated Emissions Units.

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Generator # 1
-002	Fossil Fuel Fired Steam Generator # 2

Fossil fuel fired steam generator # 1 is a nominal 468 megawatt steam generator designated as Unit # 1. The emission unit is fired primarily on bituminous coal and secondarily on No. 6 fuel oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

Fossil fuel fired steam generator # 2 is a nominal 468 megawatt steam generator designated as Unit # 2. The emission unit is fired primarily on bituminous coal and secondarily on No. 6 fuel oil and on-specification used oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

Each boiler/steam generator, units #1 and #2, drives a turbine generator and both units have an individual 550 foot exhaust stack. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Wheelabrator-Frye Inc. The control efficiency of the ESP is 99.7%. Sulfur dioxide emissions are controlled by flue gas desulfurization equipment manufactured by Combustion Engineering.

Each boiler/steam generator, units #1 and #2 are regulated under the federal Acid Rain Program, Phase II, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

{Permitting note(s): The emissions units are regulated under Acid Rain, Phase II; NSPS-40 CFR 60, Subpart Da, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(7)(b)2, F.A.C.; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD); and Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT). Fossil fuel fired steam generator # 1 began commercial operation on May 12, 1987; and, fossil fuel fired steam generator # 2 began commercial operation on June 1, 1996.}

The following specific conditions apply to the emissions units listed above:

{Permitting note: In addition to the requirements listed below, these emissions units are also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).}

A.1. Capacity. The maximum permitted heat input rate for Unit No. 1 and 2 is 4286 MMBTU/hr. Testing of emissions shall be conducted with the emissions unit operating at 90 to 100 percent of the maximum permitted heat input rate. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load 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.

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}
[Rule 62-4.160(2), and Rule 62-297.310(2), F.A.C.]

A.2. Methods of Operation - Fuels. Coal is permitted to be fired in Units No. 1 and 2. The fuel oil to be fired in Units 1 and 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. Landfill gas from the Orange County Landfill and Natural gas as supplied by commercial pipeline may be burned in Unit No. 1 and 2.
[Rules 62-4.070(3), 62-4.160(2), 62-210.200, and 62-213.440(1), F.A.C.]

A.3. Methods of Operation - Flue Gas Desulfurization System (FGD). No fraction of flue gas shall be allowed to bypass the FGD system to reheat the gases exiting from the FGD system, if the bypass will cause overall SO_2 removal efficiency less than 90 percent (or 70 percent for mass SO_2 emission rates less than or equal to 0.6 lb/million Btu 30 day rolling average). The percentage and amount of flue gas bypassing the FGD system shall be documented and records kept for a minimum of two years available for Department's inspection.
[Rule 62-4.070(3), F.A.C., 40 CFR 60.40a, and Permit No. PSD-FL-084]

A.4. Hours of Operation. Units No. 1 & 2 are allowed to operate continuously, i.e., 8760 hours/year.
[Rule 62-210.200, F.A.C., Definitions (PTE)]

Emission Limitations and Standards

A.5. Particulate matter emissions from Unit No. 1 shall not exceed 0.03 lb/million Btu heat input and 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel. Particulate matter emissions from Unit No. 2 shall not exceed 0.02 lb/million Btu heat input and 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel. This standard applies at all times except during periods of startup, shutdown, or malfunction.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.42a(a); 40 CFR 60.46a(a); 40 CFR 60.46a(c)]

A.6. Based on the maximum permitted heat input rate listed in Specific Condition A.1., the particulate matter emissions from Unit No. 1 shall not exceed 124.1 lbs/hour and 543.5 tons/year. The particulate matter emissions from Unit No. 2 shall not exceed 85.7 lbs/hr and 375.4 tons/year.
[PSD-FL-084 and Rule 62-296.700(4)(b)1., F.A.C.]

A.7. Particulate matter emissions from Units No. 1 and 2 when combusting liquid fuel (No. 6 fuel oil) shall not exceed 0.03 lb/million Btu and 30 percent of potential combustion concentration (70 percent reduction).
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(b)(1)]

A.8. Visible emissions from Units No. 1 and 2 shall not exceed 20 (twenty) percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 (twenty-seven) percent opacity.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.42a(b)]

A.9. Sulfur dioxide emissions from Unit No. 1 when combusting solid fuel shall not exceed 1.2 lb/million Btu (30 day rolling average) heat input or 1.2 lb/million Btu (2 hour emission rate) heat input. Additionally, sulfur dioxide emissions from Unit No. 1 when combusting solid fuel shall not exceed 1.14 lb/million Btu (3-hr average) heat input (4886 lbs/hr and 21,400 tons/year) and 10 percent of the potential combustion concentration (90 percent reduction) or 30 percent of the potential combustion concentration (70 percent reduction) when emissions are less than 0.60 lb/million Btu heat input.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(a)(1) and (2); PSD-FL-084]

A.10. Sulfur dioxide emissions from Unit No. 2 when combusting solid fuel shall not exceed 0.25 lb/million Btu (30 day rolling average) heat input; 0.67 lb/million Btu (24 hour emission rate) heat input or 0.85 lb/million Btu (3 hour emission rate) heat input. This corresponds to 3643 lbs/hr and 4,693 tons/year emission rate.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(a)(1); PSD-FL-084]

A.11. Sulfur dioxide emissions from Units No. 1 and 2 when combusting liquid fuel (No. 6 fuel oil) shall not exceed 0.80 lb/million Btu heat input and 10 percent of the potential combustion concentration (90 percent reduction).
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(b)(1)]

A.12. Compliance with a sulfur dioxide emission limitation and percent reduction requirements are both determined on a 30-day rolling average basis.
[Rule 62.204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(g)]

A.13. When different fuels are combusted simultaneously in Unit No. 1, the applicable standard of sulfur dioxide is determined by proration using the following formula:
(1) If emissions of sulfur dioxide to the atmosphere are greater than 0.60 lb/million Btu heat input

$$E_s = \text{the lesser of } (0.80x + 1.20y)/100 \text{ or } 1.14 \text{ and } \%P_s = 10$$

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 0.60 lb/million Btu heat input:

Es = the lesser of (0.80x + 1.20y)/100 or 1.14 and %Ps = (10x + 30y)/100

where:

Es = the sulfur dioxide emission limit (lb/million Btu heat input),
%Ps = the percentage of potential sulfur dioxide emission allowed.
x = the percentage of total heat input derived from the combustion of liquid fuel
y = the percentage of total heat input derived from the combustion of solid fuel

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(h); PSD-FL-084]

A.14. When different fuels are combusted simultaneously in Unit No. 2, the applicable standard of sulfur dioxide is determined by proration using the following formula:
(1) If emissions of sulfur dioxide to the atmosphere are greater than 0.60 lb/million Btu heat input

Es = the lesser of (0.80x + 1.20y)/100 or 0.85 and %Ps = 10

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 0.60 lb/million Btu heat input:

Es = the lesser of (0.80x + 1.20y)/100 or 0.85 and %Ps = (10x + 30y)/100

where:

Es = the sulfur dioxide emission limit (lb/million Btu heat input),
%Ps = the percentage of potential sulfur dioxide emission allowed.
x = the percentage of total heat input derived from the combustion of liquid fuel
y = the percentage of total heat input derived from the combustion of solid fuel

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(h); PSD-FL-084]

A.15. Nitrogen dioxide emissions from Units No. 1 and 2 when combusting bituminous coal shall not exceed 0.60 lb/million Btu heat input and 0.17 lb/million Btu heat input respectively. Based upon a heat input of 4136 million Btu/hour for Unit No. 1, NO_x emissions shall not exceed 2482 lb/hr (10,869 TPY). Based upon a heat input of 4286 million Btu per hour for Unit No. 2, NO_x emissions shall not exceed 729 lb/hr (3191 TPY). Nitrogen dioxide emissions from Units No. 1 and 2 when combusting liquid fuel shall not exceed 0.30 lb/million Btu heat input. These emission limits are based on a 30-day rolling average. These standards apply at all times except during periods of startup, shutdown, or malfunction.
Beginning January 1, 2000 and pursuant to 40 CFR 76.11, the FDEP approves a NOx emissions averaging plan for Units No. 1 and 2 as summarized in Section IV, Subsection A2.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.44a(a); 40 CFR 60.46a(b); 40 CFR 60.46a(c)]

A.16. When liquid and solid fuels are combusted simultaneously in Unit No. 1, the applicable standard for nitrogen dioxides is determined by proration using the following formula:

En = [0.30 x + 0.60 y]/100

where:

En = the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (lb/million Btu heat input);
x = the percentage of total heat input derived from the combustion of liquid fuels
y = the percentage of total heat input derived from the combustion of solid fuels
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.44a(c)]

A.17. When liquid and solid fuels are combusted simultaneously in Unit No. 2, the applicable standard for nitrogen dioxides is determined by proration using the following formula:

En = [0.30 x + 0.17 y]/100

where:
En = the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (lb/million Btu heat input);
x = the percentage of total heat input derived from the combustion of liquid fuels
y = the percentage of total heat input derived from the combustion of solid fuels
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.44a(c)]

A.18. Carbon monoxide (CO) emissions from Unit No. 2 shall not exceed 0.15 lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, CO emissions shall not exceed 643 lb/hr (2816 TPY).
[PSD-FL-084]

A.19. Volatile Organic Compounds (VOC) emissions from Unit No. 2 shall not exceed 0.015 lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, VOC emissions shall not exceed 64 lb/hr (282 TPY).
[PSD-FL-084]

A.20. Sulfuric acid mist (H_2SO_4) emissions from Unit No. 2 shall not exceed 0.033 lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, H_2SO_4 emissions shall not exceed 140 lb/hr (613 TPY).
[PPS PA 81-14/SA1]

A.21. Beryllium (Be) emissions from Unit No. 2 shall not exceed 5.2×10^{-6} lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Be emissions shall not exceed 0.022 lb/hr (0.1 TPY).
[PPS PA 81-14/SA1]

A.22. Mercury (Hg) emissions from Unit No. 2 shall not exceed 1.1×10^{-5} lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Hg emissions shall not exceed 0.046 lb/hr (0.2 TPY).
[PPS PA 81-14/SA1]

A.23. Lead (Pb) emissions from Unit No. 2 shall not exceed 1.5×10^{-4} lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Pb emissions shall not exceed 0.64 lb/hr (2.8 TPY).
[PPS PA 81-14/SA1]

A.24. Fluorides (Fl) emissions from Unit No. 2 shall not exceed 4.2×10^{-4} lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Fl emissions shall not exceed 1.8 lb/hr (7.9 TPY).
[PPS PA 81-14/SA1]

Compliance provisions.

A.25. The sulfur dioxide emission standards in specific conditions A.9., A.10., A.11., A.13 and A.14., apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the following procedures in specific condition A.26. are implemented.
[Rule 62-296.800(7)(b)2., F.A.C.; 40 CFR 60.46a(c)]

A.26. During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

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

(3) Operating a *spare* flue gas desulfurization system module. The Department may at their discretion require Orlando Utilities Commission within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements of specific conditions A.9., A.10., A.11., A.13 and A.14. for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,
(ii) The affected facility is operating at the maximum heat input rate,
(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Department at least 30 days notice of the date and period of time over which the demonstration will be performed.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(d)]

A.27. Compliance with the sulfur dioxide emission limitations and percentage reduction requirements in specific conditions A.9., A.10., A.11., A.13 and A.14., and the nitrogen oxides emission limitations in specific conditions A.15., A.16 and A.17., 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.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(e)]

A.28. Compliance is determined by calculating the arithmetic average of all hourly *emission rates* for SO_2 and NO_x for the 30 successive boiler operating days, except for data obtained during startup and shutdown (SO_2 & NO_x), malfunction (NO_x only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(g)]

A.29. If Orlando Utilities Commission has not obtained the minimum quantity of emission data as required in the following emission monitoring specific conditions A.30. through A.39, compliance of Units No. 1 and 2 with the sulfur dioxide and nitrogen oxides standards 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, *Determination of Compliance When Minimum Data Requirement Is Not Met.*
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(h); 40 CFR 60, Appendix A, Method 19]

Emission Monitoring.

A.30. Orlando Utilities Commission shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Department).
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(a)]

A.31. Orlando Utilities Commission shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions as follows:

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

(2) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19, Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates, may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required in the preceding specific condition A.31.(1).

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(b); 40 CFR 60, App. A, Method 19]

A.32. Orlando Utilities Commission shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxide emissions discharged to the atmosphere.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(c)]

A.33. Orlando Utilities Commission shall 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 oxide emissions are monitored.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(d)]

A.34. The continuous monitoring systems required in specific conditions A.31., A.32., and A.33., shall be operated and record data during all periods of operation of Units No. 1 and 2 including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(e)]

A.35. Orlando Utilities Commission (OUC) 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, OUC shall supplement emission data with other monitoring systems approved by the Department, or the reference methods and procedures as described in Specific Condition A.37.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a (f)]

A.36. The 1-hour averages required under 40 CFR 60.13(h), *Monitoring Requirements*, are expressed in lbs/million Btu heat input and used to calculate the average emission rates required in specific conditions A.27. and A.28. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b), *Monitoring Requirements*. At least two data points must be used to calculate the 1-hour averages.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(g)]

A.37. When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in specific condition A.35., Orlando Utilities Commission shall use the following reference methods and procedures. Acceptable alternative methods and procedures are given in specific condition A.38.

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

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

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

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

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(h); 40 CFR 60, Appendix A, Methods 3B, 6, 7, and 19]

A.38. Orlando Utilities Commission shall use the following methods and procedures to conduct the monitoring system performance evaluations required under *40 CFR 60.13(c), Monitoring Requirements,* and the calibration checks required under *40 CFR 60.13(d), Monitoring Requirements*. Acceptable alternative methods and procedures are given in specific condition A.39.

(1) Methods 6, 7, and 3B, as applicable, shall be used to determine O_2, SO_2, and NO_x concentrations

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

(3) 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)
Liquid............................	500
Solid..............................	1,000
Combination...................	500y + 1,000z

where:
y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under the preceding specific condition A.38.(3) 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 oil fuel, alone or in combination with non-fossil fuel, the span value of the fuel fired.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(i); 40 CFR 60.13; 40 CFR 60 Appendix A, Methods 3B, 6, and 7; 40 CFR 60 Appendix B, Performance Specification 2.]

A.39. Orlando Utilities Commission may use the following as alternatives to the reference methods and procedures specified in conditions A.37. and A.38.:

(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 specific condition A.38., the conditions under 40 CFR 60.46(d)(1) apply; these conditions do not apply under specific condition A.37.

(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.

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

Compliance determination procedures and methods.

A.40. In conducting the performance tests required in *40 CFR 60.8*, the owner or operator shall use as reference methods and procedures the methods in appendix A of 40 CFR 60 or the methods and procedures as specified in conditions A.41. through A.45., except as provided in *40 CFR 60.8(b). 40 CFR 60.8(f)* does not apply to specific conditions A.42 and A.43. for SO_2 and NO_x. Acceptable alternative methods are given in specific condition A.45.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(a); 40 CFR 60.8]

A.41. Orlando Utilities Commission shall determine compliance with the particulate matter standards in specific conditions A.5., A.6., A.7 and A.8 as follows:

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

(2) For the particulate matter concentration, 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 O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all

the individual O_2 concentrations at each traverse point.
(3) Method 9 and the procedures in *40 CFR 60.11* shall be used to determine opacity.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(b); 40 CFR 60.11, 40 CFR 60 Appendix A, Methods 1, 3B, 5B, 9, and 19]

A.42. Orlando Utilities Commission shall determine compliance with the SO_2 standards in specific conditions A.9., A.10., A.11., A.13 and A.14. as follows:
(1) The percent of potential SO_2 emissions (%Ps) to the atmosphere shall be computed using the following equation:

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

where:

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

(2) The procedures in Method 19 may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.
(3) The procedures in Method 19 shall be used to determine the percent SO_2 reduction ($\%R_g$ of any SO_2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.
(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.
(5) The continuous monitoring systems specified in conditions A.31. and A.33. shall be used to determine the concentrations of SO_2 and CO_2 or O_2.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a (c); 40 CFR 60 43a; 40 CFR 60.47a(b) and (d); 40 CFR 60 Appendix A, Method 19]

A.43. Orlando Utilities Commission shall determine compliance with the NO_x standards in specific conditions A.15., A.16. and A.17. as follows:
(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO_x.
(2) The continuous monitoring systems specified in specific conditions A.32. and A.33. shall be used to determine the concentrations of NO_x and CO_2 or O_2.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(d); 40 CFR 60.44a; 40 CFR 60.47a(c); 40 CFR 60.47a(d)]

A.44. Orlando Utilities Commission shall determine initial compliance with the CO, VOC, Be, Hg, Pb and Fl standards in specific conditions A.18., A.19., A.21., A.22., A.23., and A.24 respectively as follows:
(1) EPA Method 10 for CO emissions.
(2) EPA Method 18, 25, 25A or 25B for VOC emissions.
(3) EPA Method 104 for Be emissions.
(4) EPA Method 101A or 108 for Hg emissions.
(5) EPA Method 12 or 101A for Pb emissions

(6) EPA Method 13A or 13B for Fl emissions.

Orlando Utilities Commission shall conduct annual compliance tests for particulates, NO_x, SO_2 and visible emissions.
[PPS PA 81-14/SA1]

A.45. Orlando Utilities Commission may use the following as alternatives to the reference methods and procedures specified in condition A.41:

(1) For Method 5 or 5B, Method 17 may be used at Units No. 1 and 2 if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The F_c factor (CO_2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of *40 CFR 60.46(d)(1).* The CO_2 shall be determined in the same manner as the O_2 concentration.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(e); 40 CFR 60.46(d)(1); 40 CFR 60 Appendix A, Methods 5, 5B, 17, and 19]

<u>Reporting requirements</u>.

A.46. For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Department.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(a)]

A.47. For sulfur dioxide and nitrogen oxides the following information is reported to the Department for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (lb/million Btu heat input) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the 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 or 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 and shutdown (SO_2 & NO_x), malfunction (NO_x only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(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 40 CFR 60 Appendix B, Performance Specifications 2 or 3.

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

A.48. If the minimum quantity of emission data, as required by the emission monitoring specific conditions A.30. through A.39., is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of specific condition A.29. is reported to the Administrator for that 30-day period:

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

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

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

(4) The applicable potential combustion concentration.

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

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

A.49. If any sulfur dioxide standards under specific conditions A.9., A.10., A.11., A.13. or A.14. 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 specific condition A.26. 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 or lb/MMBtu) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(d); 40 CFR 60.43a; 40 CFR 60.46a(d)]

A.50. If fuel pretreatment credit is claimed toward the sulfur dioxide emission standards in specific conditions A.9., A.10., A.11., A.13. or A.14., Orlando Utilities Commission 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 specific condition A.42. and Method 19 (Appendix A of 40 CFR 60); 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.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(e), 40 CFR 60.48a(c)]

A.51. For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(f)]

A.52. 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.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(g)]

A.53. For the purposes of the reports required under *40 CFR 60.7*, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under specific condition A.8. Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(h)]

A.54. The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Department for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(i)]

Subsection B. This section addresses the following Regulated Emissions Unit.

E.U. ID No.	Brief Description
-003	Auxiliary Boiler

The auxiliary boiler is designated as Unit No. 3. The unit is a Babcock & Wilcox Model No. FM-2919 boiler. It is fired primarily with "new oil", which means an oil which has been refined from crude oil and has not been used. Only No. 2 fuel oil can be burned in the auxiliary boiler. This auxiliary boiler serves both Unit No. 1 and 2 boiler/steam generators.

{Permitting note: This emission unit is regulated under Rule 62-210.300, F.A.C., Permits Required.}

The following conditions apply to the Emission Unit listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Capacity. The maximum permitted heat input rate for Unit No. 3 is 83 MMBtu/hour.

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}
[Rule 62-210.200(PTE), F.A.C.]

B.2. Methods of Operation. Fuel. The auxiliary boiler shall be fired on No. 2 fuel oil having a sulfur content less than 0.5 percent, by weight.
[Rule 62-4.160(2), F.A.C., Construction application request]

B.3. Hours of Operation. The emission unit may operate up to 150 hours/year.
[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

B.4. Emissions from the auxiliary boiler for burning No. 2 fuel oil shall not exceed the allowable emission limits listed in the following table:

Allowable Emission Limits

Pollutant	lb/MMBtu
PM	0.015
SO_2	0.51
NO_x	0.16
Visible Emissions	20% Opacity

[Rule 62-4.160(2), F.A.C., and PSD-FL-084]

B.5. Compliance testing for PM, SO_2, NO_x, and visible emissions is not required if the unit operates for less than 400 hours annually.
[Rule 62-297.310(7)(a), F.A.C.]

B.6. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[PSD-FL-084]

Record keeping and Reporting Requirements

B.7. Documentation of the type, quantity, and analysis of the fuel oil used/received is required.
[PSD-FL-084]

Subsection C. This section addresses the following Regulated Emissions Units.

E.U. ID No.	Brief Description
-004	Coal Transfer Baghouse
-005	Coal Crusher Building Baghouse
-006	Coal Plant Transfer and Silo Fill Area #1 Baghouse
-007	Coal Plant Transfer and Silo Fill Area #2 Baghouse
-008	Limestone Day Bin Baghouse
-009	Pebble Lime Receiving Hopper Baghouse
-010	Coal Reclaim Hopper Baghouse
-011	Flyash Exhauster Filter #1 Baghouse
-012	Flyash Exhauster Filter #2 Baghouse
-013	Flyash Exhauster Filter #3 Baghouse
-014	Flyash Exhauster Filter #4 Baghouse
-015	Flyash Silo Bin Vent Filter Baghouse
-016	Adipic Acid Storage Baghouse

Descriptions

Fly Ash Silos handle fly ash from Steam Generators No. 1 and No. 2 respectively. Fly ash is pneumatically conveyed from the individual electrostatic precipitators to Silos and then is gravity fed by tubing into totally enclosed tanker trucks. Particulate matter emissions generated by silo loading and unloading to a tanker truck is controlled by baghouses in addition to reasonable precautions.

{Permitting note: The emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required.}

The following conditions apply to the Emissions Units listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Hours of Operation. Fly Ash Silos are each allowed to operate continuously, i.e., 8760 hours/year.
[Rule 62-210.200, F.A.C., Definition (PTE)]

Emission Limitations and Standards

C.2. Particulate emissions from fly ash handling system shall be limited to 0.02 gr./acf. 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 than 5% opacity will require the permittee to perform a stack test for particulate emissions.
[PPS PA 81-14/SA1]

Test Methods and Procedures

C.3. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the Orlando Utilities Commission shall have formal compliance test conducted on each silo baghouse for opacity.
[Rule 62-297.310(7)(a)4., F.A.C.]

C.4. Compliance with the opacity limit listed in C.2 will be determined by EPA Reference Method 9.
[PPS PA 81-14/SA1]

Subsection D. Common Conditions.

The following conditions apply to the Emissions Units ID -001 and -002:

40 CFR 60 Subpart A

D.1. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; Rule 62-204.800(7)(a), F.A.C.]

Notification and record keeping

D.2. The owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:
(1) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
[40 CFR 60.7(a)(4)]

D.3. The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 CFR 60.7(b)]

D.4. Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
[40 CFR 60.7(c)(1), (2), (3), and (4)]

D.5. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.
(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.
(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

{See attached Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance} (electronic file name: figure1.doc)
[40 CFR 60.7(d)(1) and (2)]

D.6. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:
(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;
(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and
(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).
(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to

the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).
[40 CFR 60.7(e)(1)]

D.7. Any owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least **5 (five)** years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

Performance tests

D.8. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
[40 CFR 60.8(c)]

Compliance with standards and maintenance requirements

D.9. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
[40 CFR 60.11(a)]

D.10. Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5).
[40 CFR 60.11(b)]

D.11. The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
[40 CFR 60.11(c)]

D.12. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
[40 CFR 60.11(d)]

D.13. The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of EPA Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he or she shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which EPA Method 9 data indicates noncompliance, the EPA Method 9 data will be used to determine opacity compliance.
[40 CFR 60.11(e)(5)]

Circumvention

D.14. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

Monitoring requirements

D.15. For the purposes of 40 CFR 60.13, all continuous monitoring systems (CMS) required under applicable subparts shall be subject to the provisions of 40 CFR 60.13 upon promulgation of performance specifications for continuous monitoring systems under Appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F of 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.
[40 CFR 60.13(a)]

D.16. If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.
(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 60.8 and as described in 40 CFR 60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 60.8 is conducted.
[40 CFR 60.13(c)(1)]

D.17. (1) Owners and operators of all continuous emission monitoring systems (CEMS) installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.
[40 CFR 60.13(d)(1) and (2)]

D.18. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems (CMS) shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:
(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.
(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
[40 CFR 60.13(e)(1) and (2)]

D.19. All continuous monitoring systems (CMS) or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of 40 CFR 60 shall be used.
[40 CFR 60.13(f)]

D.20. When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems (CMS) on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.
[40 CFR 60.13(g)]

D.21. Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).
[40 CFR 60.13(h)]

The following conditions apply to the Emissions Units ID -002 and -003:

Additional Limitations for On-Specification Used Oil

D.22. Used Oil. Burning of on-specification used oil is allowed at this facility in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Allowed as Fuel: This permit allows the burning of used fuel oil meeting EPA "on-specification" used oil specifications, with a maximum sulfur content of 1.5 percent by weight for Unit 2 and 0.5 percent by weight for the auxiliary boiler. The PCB concentration of used oil shall be less than 50 ppm. Used oil that does not meet the specifications for on-specification used oil shall not be burned at this facility.

On-specification used oil shall meet the following specifications: [40 CFR 279, Subpart B.]

Arsenic shall not exceed 5.0 ppm;
Cadmium shall not exceed 2.0 ppm;
Chromium shall not exceed 10.0 ppm;
Lead shall not exceed 100.0 ppm;
Total halogens shall not exceed 1000 ppm;
Flash point shall not be less than 100 degrees F.

b. Quantity Limited: The maximum amount of on-specification used oil that can be burned at this facility shall be limited to 1.5 million gallons during each calendar year.

c. Used Oil Containing PCBs Not Allowed: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. PCB Concentration of 2 to less than 50 ppm: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Required: The owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs, and percent sulfur content by weight, ash, and BTU value (BTU per gallon).

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods), latest edition.

If the analytical results show that the used oil does not meet the specification for on-specification used oil, or that it contains a PCB concentration of 50 ppm or greater, the owner or operator shall:

a. immediately notify the Central District Office in Orlando;
b. provide the analytical results for the above parameters; and
c. indicate the proposed means of disposal of the used oil.

f. Record Keeping Required: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department: [40 CFR 279.61 and 761.20(e)]

(1) The gallons of on-specification used oil generated and burned each month. (This record shall be completed no later than the fifteenth day of the succeeding month.)
(2) The total gallons of on-specification used oil burned in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)
(3) Results of the analyses required above.
(4) The total amount of lead emitted from burning used oil each month (calculated from the amount burned, the specific gravity of the used oil and the concentration of lead in the used oil), and the total amount of lead emitted in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)

g. Reporting Required: The owner or operator shall submit to Central District Office in Orlando, within thirty days of the end of each calendar quarter, the analytical results and the total amount of on-specification used oil generated and burned during the quarter.

Also, the owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761]

Section IV. This section is the Acid Rain Part.

Operated by: Orlando Utilities Commission
ORIS code: 0564

Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions units listed below are regulated under Acid Rain Part, Phase II.

E.U. ID No.	Description
-001	Fossil Fuel Fired Steam Generator No. 1
-002	Fossil Fuel Fired Steam Generator No. 2

A.1. The Acid Rain Part application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these acid rain units must comply with the standard requirements and special provisions set forth in the application listed below:

a. DEP Form No. 62-210.900(1)(a), dated 07/01/95.

[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO_2) allowance allocations and nitrogen oxide (NOx) limitations for each Acid Rain unit:

E.U. ID No.	EPA I.D.	Year	2000	2001	2002	2003
-001	**1**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	11199*	11199*	11199*	11199*
		NO_x limit	0.60** lb/MMBtu	0.60** lb/MMBtu	0.60** lb/MMBtu	0.60** lb/MMBtu
-002	**2**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	0*	0*	0*	0*
		NO_x limit	0.17*** lb/MMBtu	0.17*** lb/MMBtu	0.17*** lb/MMBtu	0.17*** lb/MMBtu

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2, 3, or 4 of 40 CFR 73.

** *Pursuant to 40 CFR 76.11, the FDEP approves a NOx emissions averaging plan for this unit, effective from calendar years 2000 through 2004. Under the plan, this unit's NOx emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.60 lb/MMBtu. In addition, this unit shall not have an annual heat input greater than 36231360 MMBtu.*

*** *Pursuant to 40 CFR 76.11, the FDEP approves a NOx emissions averaging plan for this unit, effective from calendar years 2000 through 2004. Under the plan, this unit's NOx emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.17 lb/MMBtu. In addition, this unit shall not have an annual heat input less than 19409657 MMBtu.*

Under the plan, the actual Btu-weighted annual average NOx emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirements of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.440(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c), F.A.C.]

A.4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Comments, notes, and justifications: None.

Appendix U-1. List of Unregulated Emissions Units and/or Activities.

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'insignificant emissions units'.

Emissions Unit	Description
-xxx	Surface Coating and Solvent Cleaning
-xxx	General Purpose Engines
-xxx	Fuel Storage Tanks
-xxx	Helper Cooling Towers
-xxx	Emergency Generators

Appendix I-1, List of Insignificant Emissions Units and/or Activities.

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rule 62.210.300(3)(a), F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

1	Lube Oil System Vents
2	Lube Oil Reservoir Tank
3	Oil Water Separators
4	Fixated Ash Disposal
5	Parts Washers/Degreasers
6	Waste Oil Storage Tanks
7	Lube Oil Storage Building
8	Portable Unleaded Gasoline Tank
9	Evaporation of non-hazardous boiler cleaning chemical
10	Sulfuric Acid Tanks

Table 1-1, Summary of Air Pollutant Standards and Terms

Orlando Utilities Commission **PROPOSED Permit No.: 0950137-001-AV**
Stanton Energy Center **Facility ID No.: 0950137**

E.U. ID Nos. Brief Description

-001 Fossil Fuel Fired Steam Generator #1

			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
PM Emissions	Coal F.O.	8760	0.03 lb/MMBtu 0.03 lb/MMBtu			128.6	563.2	Rule 62-204.800(7)(b)2, F.A.C. Rule 62-204.800(7)(b)2, F.A.C.	A.5, A.6 A.7
Visible Emissions	Coal F.O.	8760	20% Opacity					Rule 62-204.800(7)(b)2, F.A.C.	A.8
Sulfur Dioxide	Coal F.O.	8760	1.14 lb/MMBtu 0.80 lb/MMBtu			4886	21,400	Rule 62.204.800(7)(b)2, F.A.C. Rule 62-204.800(7)(b)2, F.A.C.	A.9,Sec IV-A2 A.11
Nitrogen Oxide	Coal F.O.	8760	0.60 lb/MMBtu 0.30 lb/MMBtu			2571	11,263	Rule 62-204.800(7)(b)2, F.A.C. Rule 62-204.800(7)(b)2, F.A.C.	A.15,Sec IV-A2 A.15

-002 Fossil Fuel Fired Steam Generator #2

			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
PM Emissions	Coal F.O.	8760	0.02 lb/MMBtu 0.03 lb/MMBtu			85.7	375.4	Rule 62.204.800(7)(b)2, F.A.C.	A.5, A.6 A.7
Visible Emissions	Coal F.O.	8760	20% Opacity					Rule 62.204.800(7)(b)2, F.A.C.	A.8
Sulfur Dioxide	Coal F.O.	8760	0.25 lb/MMBtu 0.80 lb/MMBtu			3643	4693	Rule 62.204.800(7)(b)2, F.A.C. Rule 62.204.800(7)(b)2, F.A.C.	A.10,Sec IV-A2 A.11
Nitrogen Oxide	Coal F.O.	8760	0.17 lb/MMBtu 0.30 lb/MMBtu			729	3191	Rule 62-204.800(7)(b)2, F.A.C. Rule 62-204.800(7)(b)2, F.A.C.	A.15,Sec IV-A2 A.15
Carbon Monoxide	Coal	8760	0.15 lb/MMBtu			643	2816	PSD-FL-084	A.18
VOC	Coal	8760	0.015 lb/MMBtu			64	282	PSD-FL-084	A.19
Sulfuric Acid Mist	Coal	8760	0.033 lb/MMBtu			140	613	PPS PA 81-14/SA1	A.20
Beryllium	Coal	8760	$5.2x10^{-6}$ lb/MMBtu			0.022	0.1	PPS PA 81-14/SA1	A.21
Mercury	Coal	8760	$1.1x10^{-5}$ lb/MMBtu			0.046	0.2	PPS PA 81-14/SA1	A.22
Lead	Coal	8760	$1.5x10^{-4}$ lb/MMBtu			0.64	2.8	PPS PA 81-14/SA1	A.23
Fluorides	Coal	8760	$4.2x10^{-4}$ lb/MMBtu			1.8	7.9	PPS PA 81-14/SA1	A.24

*Unit No.1 shall fire "new oil". Unit No.2 shall fire "new oil" as well as on-specification used fuel oil as per specific condition D.22.

** The "Equivalent Emissions" listed are for informational purposes only.

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Table 1-2, Summary of Air Pollutant Standards and Terms

Orlando Utilities Commission
Stanton Energy Center

PROPOSED Permit No.: 0950137-001-AV
Facility ID No.: 0950137

E.U. ID Nos. **Brief Description**

-003 Auxiliary Boiler #3

			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
PM Emissions	F.O.	150	0.015 lb/MMBtu			1.2	0.1	Rules 62-4.160(2), F.A.C.	B.4
Visible Emissions	F.O.	150	20% Opacity					Rule 62-4.160(2), F.A.C.	B.4
Sulfur Dioxide	F.O.	150	0.51 lb/MMBtu			42.3	3.2	Rule 62-4.160(2), F.A.C.	B.4
Nitrogen Oxide	F.O.	150	0.16 lb/MMBtu			13.3	0.1	Rule 62-4.160(2), F.A.C.	B.4

-004, -005, -006, and -007 Fly Ash Silo System

			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
Visible Emissions	N/A	8760	5% Opacity					PPS PA 81-14/SA1	C.2

* The auxiliary boiler is fired primarily with No. 2 "new oil" having a sulfur content less than 0.5 percent, by weight.
** The "Equivalent Emissions" listed are for informational purposes only.

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Table 2-1, Summary of Compliance Requirements

Orlando Utilities Commission
Stanton Energy Center

PROPOSED Permit No.: 0950137-001-AV
Facility ID No.: 0950137

E.U. # -001	Fossil Fuel Fired Steam Generator #1						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
PM Emissions	Coal	EPA Method 5B	Annual	N/A	6 hours	No	A.41(2)
Visible Emissions	Coal	EPA Method 9	Annual	N/A	1 hour	Yes	A.41(3)
Sulfur Dioxide	Coal	EPA method 6	Annual	N/A	1 hour	Yes	A.37(1)
Nitrogen Oxide	Coal	EPA Method 7	Annual	N/A	1 hour	Yes	A.37(2)

E.U. # -002	Fossil Fuel Fired Steam Generator #2						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
PM Emissions	Coal	EPA Method 5B	Annual	N/A	6 hours	No	A.41(2)
Visible Emissions	Coal	EPA Method 9	Annual	N/A	1 hour	Yes	A.41(3)
Sulfur Dioxide	Coal	EPA Method 6	Annual	N/A	1 hour	Yes	A.37(1)
Nitrogen Oxide	Coal	EPA Method 7	Annual	N/A	1 hour	Yes	A.37(2)
Carbon Monoxide	Coal	EPA Method 10	Annual	N/A	N/A	No	A.44(1)
VOC	Coal	EPA Method 18	Annual	N/A	N/A	No	A.44(2)
Beryllium	Coal	EPA Method 104	Annual	N/A	N/A	No	A.44(3)
Mercury	Coal	EPA Method 101A	Annual	N/A	N/A	No	A.44(4)
Lead	Coal	EPA Method 12	Annual	N/A	N/A	No	A.44(5)
Fluorides	Coal	EPA Method 13A	Annual	N/A	N/A	No	A.44(6)

Table 2-2, Summary of Compliance Requirements

Orlando Utilities Commission
Stanton Energy Center

PROPOSED Permit No.: 0950137-001-AV
Facility ID No.: 0950137

E.U. # -003	Auxiliary Boiler #3						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
Visible Emissions	F.O.	EPA Method 9	Annual	N/A	1 hour	No	B.5

E.U. # -004,-005,-006 and -007			Fly Ash Silo System				
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
Visible Emissions	N/A	EPA Method 9	Annual	N/A	1 hour	No	C.2

1 - Frequency base date established for planning purposes only; see guidance memo and Rule 62-297.310, F.A.C.
2 - Continuous Monitoring System.
3 - EPA Method 17 may be used only if the stack gas exit temperature is less than 375 degrees F.

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Appendix H-1, Permit History/ID Number Changes

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1,2]	Revised Date(s)
-001	Fossil Fuel Steam Generation Unit #1	PPS PA 81-14	12/15/82			12/24/97
		PSD-FL-084				
-002	Pulverized Coal Fired Unit No. 2	PPS PA 81-14	12/17/91			12/24/97
		PSD-FL-084	12/23/91			

ID Number Changes (for tracking purposes):

From: **Facility ID No.**: 30ORL480137

To: **Facility ID No.**: 0950137

Notes:
1 - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
2 - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., effective 03/20/96, allows Title V Sources to operate under existing valid permits}

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Mr. Robert F. Hicks
Director, Environmental Division
Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801

ORDER EXTENDING PERMIT EXPIRATION DATE
Curtis H. Stanton Energy Center, **Facility ID No.:** 0950137-001-AV

Section 403.0872(2)(b), Florida Statutes (F.S.), specifies that any facility which submits to the Department of Environmental Protection (Department) a timely and complete application for a Title V permit "is entitled to operate in compliance with its existing air permit pending the conclusion of proceedings associated with its application."

Section 403.0872(6), F.S., provides that a proposed Title V permit which is not objected to by the United States Environmental Protection Agency (EPA) "must become final no later than fifty-five (55) days after the date on which the proposed permit was mailed" to the EPA.

Pursuant to the Federal Acid Rain Program as defined in Rule 62-210.200, Florida Administrative Code (F.A.C.), all Acid Rain permitting must become effective on January 1 of a given year.

This facility, which will be permitted pursuant to Section 403.0872, F.S., (Title V permit) will be required to have a permit effective date subsequent to the final processing date of the facility's Title V permit.

To prevent misunderstanding and to assure that the above identified facility continues to comply with existing permit terms and conditions until its Title V permit becomes effective, it is necessary to extend the expiration date(s) of its existing valid permit(s) until the effective date of its Title V permit. Therefore, under the authority granted to the Department by Section 403.061(8), F.S., **IT IS ORDERED:**

1. The expiration date(s) of the existing valid permit(s) under which the above identified facility is currently operating is (are) hereby extended until the effective date of its permit issued pursuant to Section 403.0872, F.S., (Title V permit);
2. The facility shall comply with all terms and conditions of its existing valid permit(s) until the effective date of its Title V permit;
3. The facility will continue to comply with the requirements of Chapter 62-214, F.A.C., and the Federal Acid Rain Program, as defined in Rule 62-210.200, F.A.C., pending final issuance of its Title V permit.

PETITION FOR ADMINISTRATIVE REVIEW

The Department will take the action described in this Order unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/488-9730; Fax: 850/487-4938). Petitions filed by the permit applicant or any of the parties listed below must be filed within 14 days of receipt of this Order. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the public notice or within 14 days of receipt of this Order, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination;

(c) A statement of how and when each petitioner received notice of the agency action or proposed action;

(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;

(e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; and,

(f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and,

(g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this Order. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation will not be available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this Order.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. The petition must specify the following information:

(a) The name, address, and telephone number of the petitioner;
(b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any;
(c) Each rule or portion of a rule from which a variance or waiver is requested;
(d) The citation to the statute underlying (implemented by) the rule identified in (c) above;
(e) The type of action requested;
(f) The specific facts that would justify a variance or waiver for the petitioner;
(g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and,
(h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2), F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This Order constitutes final agency action unless a petition is filed in accordance with the above paragraphs.

RIGHT TO APPEAL

Any party to this Order has the right to seek judicial review of the Order pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, MS35, 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 from the date the Notice of Agency Action is filed with the Clerk of the Department.

DONE AND ORDERED this 26th day of April, 1999, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L. Rhodes

HOWARD L. RHODES, Director
Division of Air Resources Management
Twin Towers Office Building
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
850/488-0114

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order and all copies were sent by certified mail before the close of business on 4/26/99 to the person(s) listed:

Mr. Len Kozlov, CD

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency Clerk, receipt of which is hereby acknowledged.

Barbara J. Boutwell (Clerk) 4/26/99 (Date)