Best Available Copy

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

FPL

March 30, 2005

RECEIVED

MAR 31 2006

BUREAU OF AIR REGULATION

A.A. Linero, P.E.
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Mail Station #5505
Tallahassee, FL 32399-2400

Re: Florida Power & Light Company
West County Energy Center Project
DEP File No. 0990646-001-AC (PSD-FL-354)

Dear Mr. Linero:

Florida Power & Light Company (FPL) is in receipt of the Draft Prevention of Significant Deterioration (PSD) Permit and Technical Evaluation and Preliminary Determination (TEPD) for the West County Energy Center, issued by the Department on March 1, 2006. In accordance with the Department's Notice of Intent to Issue a PSD permit, this letter and attachments convey requested corrections and clarifications in the Draft PSD and the TEPD. Specifically, attached to this letter are two documents, Attachment 1 & 2, with proposed edits to the Draft PSD and TEPD that we would like you to consider.

Thank you for the time and care you have taken in your review of the West County Energy Center Project. Please call if you have any questions. You can reach me at (561) 691-7518.

Sincerely,

Barbara P. Linkiewicz

Barbara P. Linkiewicz
Environmental Licensing Manager

cc: Steven Palmer, DEP Siting Office
Ken Kosky, Golder Associates

ATTACHMENT 1

West County Energy Center
PSD Draft Air Permit, issued March 1, 2006
Florida Power & Light Company – Comments

March 30, 2006

1. **Page 1, Expiration Date**: The Draft PSD permit has an expiration date of December 31, 2009. The commercial operation date of the West County Unit 2 is after the expiration date (June 2010). Consistent with historical DEP practice, and to allow for construction delays, the expiration date of the permit should be 18 months after commercial operation of the second unit, December 31, 2011.

2. **Page 2, Facility Description, second paragraph**: We request that the language be updated to reflect a 26-cell cooling tower as follows:

   "Each combined cycle unit will consist of: three nominal 250 megawatt Model 510G gas-turbine-electrical generator sets with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG's) with SCR reactors; one nominal 428 mmBtu/hour (LHV) gas-fired duct burner located within each of the three HRSG's; three 149 feet-exhaust stacks; one ~~24~~-26-cell mechanical draft cooling tower; and a common nominal 500 megawatt steam-electrical generator."

3. **Page 4, Relevant Documents:** We request that "Letter from FPL to DEP dated December 29, 2005" with details on Mitsubishi 501G technology, including update to nominal megawatts and size of oil tanks be added to the list of Relevant Documents.

4. **Page 7, Equipment and Control Technology, Gas Turbines:** We request the following clarification:

   "4. Gas Turbines. The permittee is authorized to install, tune, operate, and maintain six Model 501G gas turbine-electrical generator sets each with a nominal generating capacity of 250 MW…"

5. **Page 10, Emissions Standards, Footnote h:** To clarify that if a CO catalyst in installed, the rolling average will be calculated from the installation of the catalyst forward, we propose the following:

   "h. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @ 15% O2 limit for any combustion turbine / supplementary-fired heat recovery steam generator upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. ~~From time of notification to~~ After completing the installation of the catalyst, all prior partial or complete calendar months shall be excluded from the 12 month rolling average."

6. **Page 17, NSPS Applicability.** NSPS Kb is not applicable in its entirety because the fuel that is being used has a maximum true vapor pressure less than 3.5 kPa. FPL suggests that the reference to NSPS Kb be removed and the rest of the section be renumbered accordingly.

"~~NSPS APPLICABILITY~~

~~1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the record keeping requirements specified below. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]~~

EQUIPMENT SPECIFICATIONS

~~2.~~ 1. Equipment: The permittee is authorized…

EMISSIONS AND PERFORMANCE REQURIEMENTS

~~3.~~ 2. Hours of Operation…

NOTIFICATION, REPORTING AND RECORDS

~~4.~~ 3. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report.
~~[Rule 62-204.800(7)(b)16, F.A.C., 40 CFR 60.116b(a) and (b)]~~"

7. **Page 18, Equipment, Cooling Tower:** We request that the language be updated to reflect a 26-cell cooling tower as follows:

"1. Cooling Tower. The permittee is authorized to install two new ~~24-~~ 26-cell mechanical draft cooling towers with the following nominal design characteristics:…

8. **Page 18, Emissions and Performance Requirements:** Correct typo:

"2. Drift Rate. Within 60 days of commencing operation, the permittee shall ~~submit~~ certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate."

9. **Page 21, Emission Unit Description:** We request the following clarification:

"011. Four nominal 2,250 Kw Liquid Fueled Emergency Generators – Reciprocating Internal Combustion Engines"

10. **All pages, footer:** Correct typo:

"FP&L West County Energy Center"

ATTACHMENT 2

West County Energy Center
Technical Evaluation and Preliminary Determination, issued March 1, 2006
Florida Power & Light Company – Comments

March 30, 2006

1. **Page 2, Figure 1**: SW St. Lucie should be removed from this Figure, as it is no longer a proposed FPL project.

2. **Page 3, Project Description, first paragraph**: For accuracy and consistency with the Draft PSD permit, please make the corrections indicated below:

   "The applicant proposes to construct two "three-on-one" combined cycle units (Units 1 and 2). Each combined cycle unit will consist of: three nominal 250 megawatt (MW) "G" Class gas-turbine-electrical generator sets (~~probably~~ Mitsubishi Heavy Industries Model 501G) with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG's) with SCR reactors and gas-fired duct burners (nominal 428 mmBtu/hour LHV); three 149 feet-exhaust stacks; one ~~22~~-26-cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator."

3. **Page 4, Stack Parameters:** For accuracy and consistency with the Draft PSD permit, please make the correction indicated below:

   "Stack Parameters: Each heat recovery steam generator has a combined cycle stack (HRSG stack) that is at least 149 feet tall with a nominal diameter of ~~23~~ 22 feet.

4. **Page 5, Inlet Conditioning:** We request clarification of the description as follows:

   "Inlet Conditioning: Evaporative cooling is a system that allows for the injection of fine water droplets into the gas turbine compressor inlet air or inlet air is drawn through a wetted media, which reduces the gas temperature through evaporative cooling..."

5. **Page 6, Table 1, Applicant's Initial Estimated Annual Emissions for both Combined Cycle Units:** For accuracy and consistency with the PSD application and the published notice, please make the correction indicated below.

Pollutant	Project Emissions TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
CO	968	100	Yes
Pb	0.050	0.6	No
NO_x	841	40	Yes
PM/PM_{10}	~~511/211~~ 611/420	25/15	Yes
SO_2	407	40	Yes
SAM	41	7	Yes
VOC	176	40	Yes

6. **Page 7, Title 40, Description:** Delete reference to Part 76, as it only applies to coal-fired units.

7. **Page 14, first paragraph:** Update 2,200 MW to 2,500 MW for consistency with permit and selected technology:

"Estimates provided by FPL for the proposed ~~2,200~~ 2,500 MW project also indicate a large cost difference between the two technologies..."

8. **Page 14, Table 3:** There is a question mark after "DB" in the NOx Limit and Fuel column for the Wolf Hollow, TX project.

9. **Page 16, Table 6:** There is a question mark next to "NH_3" in the "PM-lb/mmBTU or lb/hr NH_3 – ppmvd @ 15% 0_2" column for the West County project.

10. **Page 18, Section 4.3 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination, paragraph 4:** For accuracy and consistency with the PSD application, please make the correction indicated below:

"FPL estimated ~~206~~ 203.5 tons per year of SO_2 and 20 tons per year of sulfuric acid mist (SAM) per combined cycle unit. This equates to ~~412~~ 407 and 40 TPY for SO2 and SAM respectively from the two combined cycle units..."

11. **Page 19, Cooling Tower PM Emissions:** For accuracy and consistency with the PSD application and Draft PSD permit, please make the corrections indicated below:

"The applicant's preliminary design includes a ~~22~~ 26 or 24-cell mechanical draft cooling tower for each combined cycle unit with the following specifications...

"The Department determines the draft BACT to be a design drift rate of no more than 0.0005% of the circulating water flow rate. At this level, maximum potential PM and PM_{10} emissions from the cooling tower are expected to be on the order of ~~134~~ 201.2 and 10 TPY respectively from the two cooling towers."

12. **Page 20, Table 7, Draft BACT Determination, Footnote h:** To clarify that if a CO catalyst is installed, the rolling average will be calculated from the installation of the catalyst forward, we propose the following:

"h. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @ 15% O2 limit for any combustion turbine / supplementary-fired heat recovery steam generator upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. ~~From time of notification to~~ After completing the installation of the catalyst, all prior partial or complete calendar months shall be excluded from the 12 month rolling average."

13. **Page 22, National Emission Standards for Hazardous Air Pollutants Applicable to Gas Turbines, third paragraph:** FPL will meet the limit as it applies when the rule is finalized. However, we provide the following clarification because FPL did not specifically propose to meet a particular standard in our application:

"~~FPL proposes to meet the limit proposed in YYYY of 91 ppbvd.~~ The Department believes the formaldehyde emission limit will be met given the proposed BACT CO limits of 8.0 and 6 ppmvd @ 15% O_2 for daily and annual operation respectively..."

14. **Page 23, second paragraph:** We request the following clarifications:

"The ~~limits proposed~~ manufacturer's emissions data provided by FPL ~~for~~ in the West County Energy Center PSD Application are included for comparison. NSPS and NESHAP requirements that are possibly applicable to the auxiliary boilers are also included. Subpart Db requirements, which apply to boilers that are 100 MMBtu/hr or greater are included in the table below because the FPL project appears to specify a nominal 100 MMBtu/hr boiler. The 99.8 MMBtu/hr specification set by FPL must relate to a physical capacity rather than a permit condition."

15. **Page 26, 6th bullet:** We request the following clarification:

For shutdown, up to three hours in any 24-hour period of excess emissions are allowed.

16. **Page 27, first paragraph:** FPL does not intend to install a damper. For accuracy and consistency with the Draft PSD permit, please remove reference to a permit requirement for installation of a damper.

"While NOx emissions during warm and cold startups are greater than during full load stead-state operation, such startups are infrequent. Also it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation. ~~The draft permit will also require the installation of a damper to reduce heat loss during combined cycle shutdowns to minimize the number of combined cycle cold startups.~~"

17. **Page 27, second paragraph:** We request that language be clarified as proposed below to reflect that FPL will not install a separate dump condenser, but may operate in bypass mode and dump steam to the main condenser:

"Combined Cycle Operations ~~with Dump Condenser~~: If the steam-electrical turbine generator was off line for some reason, it is possible that the gas turbine / HRSG systems would operate without producing any steam generated power. Instead, steam would be delivered ~~to a dump~~ via a steam generator bypass to the condenser. ~~Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection.~~

18. **Page 27, Table 12, Major Sources of NO_x in Palm Palm Beach County (2004):** Update tons per year to be consistent with the PSD permit application.

Specifically, in the row for FPL's West County Energy Center, "856" should be "841".

19. **Page 28, Table 13, Largest Sources of SO_2 in Palm Palm Beach County (2004):** Update tons per year to be consistent with the PSD permit application.

Specifically, in the row for FPL's West County Energy Center, "411" should be "407".

20. **Page 28, Table 14, Largest Sources of PM in Palm Palm Beach County (2004):** Update tons per year to be consistent with the PSD permit application.

Specifically, in the row for FPL's West County Energy Center, "652" should be "611".

21. **Page 28, Table 15, Largest Sources of CO in Palm Palm Beach County (2004):** Update tons per year to be consistent with the PSD permit application.

    Specifically, in the row for FPL's West County Energy Center, "2020" should be "968".

    FPL also notes that the 2004 Annual Operating Report for the Riviera Power Plant was 431 tons of CO, which suggests that it should be included in Table 15.

22. **Page 35, Table 22, PSD Class I Increment Analysis – ENP**: Correct the Allowable Increment from 5 ug/m^3 to 8 ug/m^3.

23. **Page 35, Ozone, Second Paragraph:** Update tons per year to be consistent with the PSD permit application.

    "...The West County Energy Center will add ~~856~~ 841 TPY of NOx and 176 TPY of VOC..."

24. **Page 36, First Paragraph:** Update tons per year to be consistent with the PSD permit application.

    "To conclusively prove whether or not the ~~856~~ 841 TPY of NOx and 176 tons of VOC will not cause or contribute to a violation, a very sophisticated and expensive model would need to be run for the entire region..."

PERMITTEE:

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

FPL West County Energy Center
DEP File No. 0990646-001-AC
Permit No. PSD-FL-354
SIC No. 4911
Expires: December 31, 2011

Deleted: 09

PROJECT AND LOCATION

This permit authorizes the construction of two nominal 1,250 megawatt combined cycle units at the proposed Florida Power and Light Company (FPL) West County Energy Center.

The proposed project will be located at 4000 205th Street, North, in unincorporated Palm Beach County. This site encompasses 220 acres of which approximately 40 acres will be used for two combined cycle units.

UTM coordinates are Zone 17; 562.19 km E; 2953.04 km N.

STATEMENT OF BASIS

This PSD construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

Michael G. Cooke, Director (Date)
Division of Air Resources Management

FACILITY DESCRIPTION

The FPL West County Energy Center will be a nominal 2,500 megawatt (MW) greenfield power plant. The initial phase is the construction of two nominal 1,250 MW gas-fired combined cycle units that will use ultralow sulfur (ULS) fuel oil as backup fuel. The two combined cycle units are designated as Unit 1 and Unit 2.

Each combined cycle unit will consist of: three nominal 250 megawatt Model 501G gas turbine-electrical generator sets with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG's) with SCR reactors; one nominal 428 mmBtu/hour (LHV) gas-fired duct burner located within each of the three HRSG's; three 149 feet exhaust stacks; one 26 cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator.

Deleted: 24-

Additional ancillary equipment will include: four emergency generators; two natural gas fired fuel heaters; two diesel fuel storage tanks; two auxiliary steam boilers; and other associated support equipment.

{Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}

NEW EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
001	Unit 1A – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
002	Unit 1B – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
003	Unit 1C – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
004	Unit 2A – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
005	Unit 2B – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
006	Unit 2C – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
007	Two nominal 6.3 million distillate fuel oil storage tanks*
008	Two 26 cell mechanical draft cooling towers
009	Two nominal 85,000 lb/hr (99.8 MMBtu/hr) auxiliary boilers
010	Two nominal 10 MMBtu/hr gas-fired process heaters
011	Four nominal 2,250 KW (~ 21 MMBtu/hr) emergency generators
012	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank

* This capacity will allow approximately 108 hours of on-site oil storage

REGULATORY CLASSIFICATION

Title III: This facility will be major for hazardous air pollutants (HAPs).

Title IV: The facility will operate emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the new facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Deleted: &

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A: Subparts A from NSPS 40 CFR 60 and NESHAP 40 CFR63; Identification of General Provisions.

Appendix BD: Final BACT Determinations and Emissions Standards.

Appendix Da: NSPS Requirements for Duct Burners, 40 CFR 60, Subpart Da.

Appendix Dc: NSPS Requirements for Small Steam Generating Units, 40 CFR 60, Subpart Dc.

Appendix DDDDD: NESHAP Requirements for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD.

Appendix GC: General Conditions.

Appendix GG: NSPS Requirements for Gas Turbines, 40 CFR 60, Subpart GG.

Appendix SC: Standard Conditions.

Appendix XS: Semiannual NSPS Excess Emissions Report.

Appendix YYYY: NESHAP Requirements for Gas Turbines, 40 CFR 63, Subpart YYYY.

Appendix ZZZZ: NESHAP Requirements for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ.

The following 40 CFR 60, New Source Standard Performance (NSPS) subparts, shall become part of this permit on the effective final date of each regulation:

Standards of Performance (NSPS) for Stationary Compression Ignition Internal Combustion Engines (ICE), 40 CFR 60, Subpart IIII; Proposed Rule (published July 11, 2005). This subpart will be eventually incorporated as Appendix IIII.

Standards of Performance (NSPS) for Stationary Gas Turbines, 40 CFR 60 Subpart KKKK; Proposed Rules (published February 18, 2004). This subpart will be eventually incorporated as Appendix KKKK.

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on April 14, 2005;
- Department PSD Application Sufficiency comments dated June 13, 2005;
- Sufficiency Responses received August 12, 2005;
- Letter from FPL to DEP dated December 29, 2005;
- Draft permit package issued on March 1, 2006;
- Final Certification by the Power Plant Siting Board on Month Day, Year; and
- Final Determination distributed concurrently with Final PSD Permit.

Formatted: Bullets and Numbering

Deleted: &

- 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
- 40 CFR 60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

b *Subpart Da, Standards of Performance for Electric Utility Steam Generating Units:* These provisions include standards for duct burners.

c *Subpart GG, Standards of Performance for Stationary Gas Turbines:* These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

d *Subpart KKKK, Standards of Performance for Stationary Gas Turbines*: These provisions were published February 18, 2004 as a proposed new NSPS standard. The final rule will be applicable to Unit 001 through Unit 006 at the time of publication in the Federal Register. When the rule becomes final, Unit 001 through Unit 006 gas turbines may no longer be subject to NSPS Subparts Da and GG.

3. NESHAP Requirements: The combustion turbines are subject to 40 CFR 63, Subpart A, Identification of General Provisions and 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. (Reference: Appendix YYYY and Appendix A, NESHAP Subpart A of this permit).

EQUIPMENT AND CONTROL TECHNOLOGY

4. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain six Model 501G gas turbine-electrical generator sets each with a nominal generating capacity of 250 MW. Each gas turbine shall include an automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The gas turbines will utilize DLN combustors. [Application; Design]

5. HRSGs: The permittee is authorized to install, operate, and maintain six new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover exhaust heat energy from one of the six gas turbines (1A to 1C and 2A to 2C) and deliver steam to one of the two steam turbine electrical generators. Each HRSG may be equipped with a gas-fired duct burner having a nominal heat input rate of 428 MMBtu per hour (LHV).

6. Gas Turbine/Supplementary-fired HRSG Emission Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the DLN system to control NO_X emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from each gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

Deleted: &

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane. The limits apply only at high load (90-100% of the combustion turbine capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

h. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any combustion turbine/supplementary-fired heat recovery steam generator upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

* FPL requested change here. Did not change.

{"DB" means duct burning. "SCR" means selective catalytic reduction. "NA" means not applicable}.

[Rule 62-212.400(BACT), F.A.C.]

13. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da.

{Permitting Note: The BACT limits applicable during duct firing are much more stringent than the standards of NSPS Subpart Da for duct burners. Therefore compliance with the BACT limits insures compliance with the emission limitations in Subpart Da} [Subpart Da, 40 CFR 60]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 12 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

14. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

15. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

16. Definitions

a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(245), F.A.C.]

b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(230), F.A.C.]

Deleted: &

B. DISTILLATE FUEL OIL STORAGE TANK (EU 007)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
007	Two Nominal 6.3 million gallon distillate fuel oil storage tanks

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

   The listed emission units shall comply with 40 CFR 60, Subpart Kb only to the extent that the regulations apply to the emission unit and its operations.

Deleted: except for the record keeping requirements specified below

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain two 6.3 million gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C.]

Deleted: 62-204.800(7)(b)16, F.A.C.; 40 CFR 60.116b(a) and (b)

5. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. [62-4.070(3) F.A.C.]

Formatted: Body Text,SCA Body Text,SCA Body Text1,SCA Body Text2,SCA Body Text11, Left, Numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 0" + Tab after: 0.25" + Indent at: 0.25", Widow/Orphan control, Tabs: Not at 0.5" + 0.75" + 1" + 1.25" + 1.5"

When we removed Kb applicability we ~~=~~ not added this.

Deleted: &

C. COOLING TOWER (EU 008)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
008	Two 26-cell mechanical draft cooling towers

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install two new 26-cell mechanical draft cooling towers with the following nominal design characteristics: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

Deleted: 4

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM_{10} per year. Actual emissions are expected be lower than these rates.}*. [Rule 62-212.400(BACT), F.A.C.]

Deleted: submit

Deleted: &

EMERGENCY GENERATOR (011)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
011	Four ~~nominal~~ 2,250 Kw Liquid Fueled Emergency Generators – Reciprocating Internal Combustion Engines

NESHAPS APPLICABILITY

1. NESHAPS Subpart ZZZZ Applicability: These emergency generators are Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and are subject to 40 CFR 63, Subpart ZZZZ. They shall comply with 40 CFR 63, NESHAP Subpart ZZZZ only to the extent that the regulations apply to the emissions unit and its operations.

   [40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) and Rule 62-204.800(11)(b)80, F.A.C.]

NSPS APPLICABILITY

2. NSPS Subpart IIII Applicability: These emergency generators are Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and are subject to 40 CFR 60, Subpart IIII. They shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emission unit and its operations (e.g. non-road, emergency, displacement, capacity, model year selected).

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Proposed Rule- Federal Register Vol. 70, No. 131, July 11, 2005. Pages 39869 – 39904].

EQUIPMENT SPECIFICATIONS

3. Equipment: The permittee is authorized to install, operate, and maintain four 2,250 Kw emergency generators. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

4. Hours of Operation and Fuel Specifications: The hours of operation shall not exceed 160 hours per year per each generator. The generators are allowed to burn 0.0015% sulfur fuel oil.
   [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

5. Emergency Generators BACT Emissions Limits:

NO_X	CO	Hydrocarbons[1]	SO_2	PM/PM_{10}
6.9 gm/bhp-hr	8.5 gm/bhp-hr	1.0 gm/bhp-hr	0.0015% S F.O.	0.4 gm/bhp-hr

   Note 1. Hydrocarbons are surrogate for VOC.

   {The Draft BACT limits are equal to the values corresponding to the Tier 1 values cited in the proposed rule 40 CFR 60, Subpart IIII. The Final BACT will be revised to comport with the final rule when issued.}

6. Emergency Generators Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit. As an alternative, an EPA Certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values and the use of ULS fuel oil can be used to fulfill this requirement.

Deleted: &

REVISIONS OF DRAFT PERMIT

WEST COUNTY ENERGY CENTER
COMBINED CYCLE POWER PROJECT
DEP FILE NO. 09906461-001-AC (PSD-FL-354)

The following is a list of revisions to the WCEC draft permit (PSD-FL-354). Changes are highlighted. Deletions are shown as double strikethrough, and additions are underlined.

1. The expiration date has been extended to December 31, 20~~9~~11. (Page 1 of permit)
2. Section I, Facility Description, second paragraph, number of cells in cooling tower (page 2 of permit):

   Each combined cycle unit will consist of: three nominal 250 megawatt Model 501G gas turbine-electrical generator sets with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG's) with SCR reactors; one nominal 428 mmBtu/hour (LHV) gas-fired duct burner located within each of the three HRSG's; three 149 feet exhaust stacks; one ~~24~~26 cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator.
3. Section I, Relevent Documents. (added a document) (page 4 of permit):
   - Letter from FPL to DEP dated December 29, 2005;
4. Section III, Subsection A, Condition 4, added the word "nominal" (page 7 of permit):
   4. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain six Model 501G gas turbine-electrical generator sets each with a nominal generating capacity of 250 MW. Each gas turbine shall include an automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The gas turbines will utilize DLN combustors. [Application; Design]
5. Section III, Subsection B, Conditions 1, 4 and 5 (page 17 of permit):
   1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb~~, except for the record keeping requirements specified below~~. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.].
   4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C.~~62-204.800(7)(b)16, F.A.C., 40CFR 60.116b(a) and (b)~~]
   5. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. [62-4.070(3) F.A.C.]

6. Section III, Subsection C., Condition 1, changed 24-cell to 26-cell, and Condition 2 deleted the word submit (page 18 of permit):

    1. Cooling Tower: The permittee is authorized to install two new 26~~4~~-cell mechanical draft cooling towers with the following nominal design characteristics: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design.]

    2. Drift Rate: Within 60 days of commencing operation, the permittee shall ~~submit~~ certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM_{10} per year. Actual emissions are expected be lower than these rates.}*. [Rule 62-212.400(BACT), F.A.C.

7. Section III, Emergency Generator, Emission Unit Description Table, added the word "nominal" (page 21 of permit):

ID	Emission Unit Description
011	Four nominal 2,250 Kw Liquid Fueled Emergency Generators – Reciprocating Internal Combustion Engines

8. All pages, Footer, correct typo:

    FP~~&~~L

PROPOSED PERMIT CHANGES

Summary of proposed permit changes

Existing Permit Condition	Proposed Permit Condition	Proposed Change
		Change permit expiration date to 01-01-10
		Change PWEU2 to PWEU1 throughout the permit
3	3	Add emission unit ABEU1 for the natural gas fired auxiliary boiler
Table 2	Table 2	Add emission unit ABEU1 and applicable requirements to table
9 & 10	9 & 10	Expand applicability of conditions to include ABEU1
NA	17 & 18	Add BACT conditions for ABEU1
NA	19	Add PSD limit for ABEU1
NA	23	Add NSPS Subpart Dc requirements for auxiliary boiler, ABEU1
26	29	Change sulfur monitoring requirements for PWEU1
33	36	Reduce PSEL for all pollutants
43	46	Expand PSEL monitoring requirements to address ABEU1
46	49	Expand recordkeeping requirements to address ABEU1

5. The original proposed facility included electric auxiliary boilers, which had no emissions. The electric auxiliary boilers lack turndown capability and will not work on a G-Class turbine. PGE submitted an application to modify the permit to allow installation of a single 91 MMBtu/hour natural gas fired boiler with a 10 to 1 turndown capability. Maximum emissions from the proposed boiler in tons per year are projected as follows:

Projected annual emissions from Auxiliary Boiler in tons

EU	PM/PM_{10}	CO	NO_X	SO_2	VOC
ABEU1	0.1*	2.7	1.6	0.1*	0.2*

* These emissions are significantly less than 1 tpy and are included with insignificant activities for compliance calculation purposes.

6. The proposed auxiliary boiler (ABEU1) is subject to the following specific applicable requirements:

Auxiliary Boiler Applicable Requirements

Applicable Requirement	Pollutant/Parameter	Limit/Standard	Monitoring
340-208-0110(2) and (3)	Visible emissions	20% opacity, 3 min. in 60 min.	Fuel recordkeeping
340-226-0210(1)(b)	PM	0.1 gr/dscf	Fuel recordkeeping
340-208-0610(1)(a)	PM	0.14 lb/10^6 Btu heat input	Fuel recordkeeping
BACT 340-224-0070(1)	NO_X	Low NO_X burner, 4.55 lb/hr	Hours of operation and source test
BACT 340-224-0070(1)	CO, VOC, PM/PM_{10}, SO_2	Pipe line quality NG	Fuel Recordkeeping
NSPS 40CFR60.48.c	Operation	Hours	Recordkeeping

7. The proposed auxiliary boiler will only burn natural gas. Visible emissions from the boiler are unlikely and particulate emissions will be minimal. Compliance is determined by periodic visual emission surveys. As long as there are no visible emissions the emission unit is judged to be operating in compliance with both particulate and visible emission standards.

8. The proposed auxiliary boiler is new equipment and is subject to New Source Review/Prevention of Significant Deterioration as part of the original Port Westward project. A BACT analysis for the proposed boiler concluded that BACT for NOx would be using Low-NO_X burners with a NO_X emission limit of 4.55 pounds per hour. Being it is unlikely that emissions would exceed this limit and considering that annual NO_X emissions are estimated to be less than 1.6 tons per year, a source test is not required unless the unit is operated more than 2000 hours in any calendar year. See Appendix B for a detailed discussion of the BACT analysis.

9. An auxiliary boiler BACT analysis for PM/PM_{10}, CO, SO_2, and VOC determined that BACT is the use of pipeline quality natural gas. See Appendix B for a detailed discussion of the BACT analysis.

10. While the addition of the auxiliary boiler does not cause an increase in emissions over those originally proposed, the original air quality analysis was revisited to ensure allowable modeling thresholds are not exceeded. The analysis confirmed that ambient concentrations of criteria pollutants do not exceed applicable thresholds.

11. The proposed auxiliary boiler (ABEU1) is rated at 91 MMBtu/hour and is subject to 40 CFR 60.48.c (NSPS Subpart Dc). The applicable requirements include maintaining a record of the type and amount of fuel used and the hours of operation. The records must be maintained on site for a minimum of two years. There are no reporting requirements other than notification of the date construction commences for the boiler and notification of the actual date of initial boiler startup.

12. Constructing one G-Class turbine instead of two F-Class turbines reduces the projected emissions from, and PTE of, the proposed Port Westward project. Addendum No. 2 reduces the PSELs, including insignificant activities, accordingly, as follows:

Proposed PSELs

Pollutant	Original PSEL	Proposed PSEL*
PM/PM_{10}	118	87
CO	225	99
NO_X	234	157
SO_2	57	41
VOC	69	39

* See Appendix A for emission calculations.

PUBLIC NOTICE

13. The proposed significant permit modification is considered a Category III permit action and public notice is required. The proposed permit was placed on public notice for 35 days from February 26, 2005 to April 4, 2005 to allow the public to submit written comments. No requests for a hearing were received, no comments on the draft permit were received.

05-0008 P A2 RR
JAB
12/09/04

that has already been demonstrated in practice." On page B-18 of the *Draft New Source Review Workshop Manual,* EPA again specifies that a technology must be commercially available to be considered: "A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique."

2. **Eliminate technically infeasible options.** The technical feasibility of the control options identified in Step 1 is evaluated with respect to the source-specific factors. This demonstration should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emission unit under review. Technically infeasible control options then are eliminated from further consideration in the BACT analysis.

3. **Rank remaining control technologies by control effectiveness.** This ranking should include control efficiencies, expected emission rate, expected emissions reduction, energy impacts, environmental impacts, and economic impacts. If the top control alternative is chosen, then cost and other detailed information about other control options need not be provided.

4. **Evaluate the most effective controls and document results, including a case-by-case consideration of energy, environmental, and economic impacts.** If the top control alternative is selected, impacts of unregulated air pollutants or impacts in other media are considered to determine if the selection of an alternative control option can be justified. If the top control option is not selected as BACT, evaluate the next most effective control option.

5. **Select BACT,** which will be the most effective option not rejected in Step 4.

The BACT analysis was performed using a search of EPA's RACT/BACT/LAER Clearinghouse (RBLC) at http://cfpub1.epa.gov/rblc/htm/bl02.cfm, review of recent permitting actions, vendor information, and input from engineering contractors.

BACT Summary

Based on the findings from this auxiliary boiler BACT analysis, the following control technologies represent BACT:

- Low-NOx burners for control of NOx
- Good combustion for control of CO, VOCs, and PM/PM_{10}

Details of the BACT analysis for each pollutant are provided below.

BACT for NOx

A search of the RBLC database for auxiliary boiler BACT limits listed low-NOx burners, good combustion, and flue gas recirculation (FGR) as control technologies for controlling NOx emissions. Ultralow-NOx burners were not found in the RBLC as a control technology for auxiliary boilers supporting turbine startup.
Additionally, in our discussions with manufacturing representatives from Todd, Coen, English Boilers and others, low-NOx burners are recommended for the 10:1 turn down ratio required for the facility. The Ultralow-NOx burner is restricted by a turn down ratio on the order of 6:1 in order to achieve emission limits under 10 parts per million (ppm) NOx. Problems arise when trying to achieve a higher turn down (greater than 6:1) with the ultralow-NOx burner because the flue gas recirculation comprises approximately one-third of the combustion mixture, and there is no mixing with the other combustion gases, preventing operation at low fuel use (i.e., turn down) levels. The ultralow-NOx burner was therefore determined to be technically infeasible for the facility, because of the need for a 10:1 turn down ratio.

Although, as described above, the ultralow-NOx burner was determined to be technically infeasible, and therefore not considered further in the BACT analysis, its costs are significantly higher as well. Manufacturer representatives advised that the burner management system and required combustion controls associated with ultralow-NOx burners would cost a minimum of $100,000 more than low-NOx burners.

Detailed information about NOx emission limits and control technologies were obtained from the RBLC for natural gas-fired auxiliary boilers permitted from 2002 to present (maximum design heat input rating between 10 and 100 MMBtu/hr), as summarized in Table 1.

TABLE 1
Recent NOx Limits for Natural Gas-Fired Auxiliary Boiler Projects for Combustion Turbines

Emission Limit	Turbine Equipment	Aux. Boiler Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER	Reference
0.035 lb/MMBtu	(4) GE 7FA	Good combustion[1]	12/30/2003	Peoples Energy Resources COB Energy Facility, LLC-OR	BACT	RBLC/ DEQ Permit Review Report
0.055 lb/MMBtu	(2) GE 7FA	Good combustion	03/24/2003	Genpower Rincon, LLC Rincon Power Plant-GA	BACT	RBLC
0.05 lb/MMBtu	(2) GE 7FA	Low NOx	03/21/2003	Duke Energy Duke Energy Stephens, LLC-OK	BACT	RBLC
30 ppm @3% O_2 (3hr-ave.)	Not Listed	Good combustion	03/12/2003	Klamath Generation, LLC-OR	BACT	RBLC
0.23 lb/MMBtu	(4) GE 7FA	Low NOx, Flue Gas Recirculation	01/03/2003	Wallula Generation, LLC Wallula Power Plant-WA	BACT	RBLC
0.049 lb/MMBtu	(2) GE 7FA	Dry Low NOx	12/20/2002	Interstate Power & Light Emery Generating Station-IA	BACT	RBLC
3.2 lb/hr, 0.08 lb/MMBtu	(4) GE 7FA	Low NOx	11/21/2002	Cogentrix Energy Inc. Henry County Power-VA	BACT	RBLC
0.036 lb/MMBtu	(2) GE 7FA	Low NOx	11/18/2002	Virginia Power VA Power-Possum Point-VA	BACT	RBLC
0.037 lb/MMBtu	(4) GE 7FA	Dry Low NOx, Flue Gas Recirculation	10/23/2002	Duke Energy Murray, LLC Murray Energy Facility-GA	BACT	RBLC
3.82 lb/hr, 0.05 lb/ MMBtu	Not Listed	Low NOx	09/06/2002	Competitve Power Venture CPV Cunningham Creek-VA	BACT	RBLC
0.04 lb/MMBtu	Not Listed	Low NOx	08/23/2002	Genova Arkansas I, LLC-AR	BACT	RBLC
0.034 lb/MMBtu	(2) GE 7FA	Good combustion	07/23/2002	Entergy Hawkeye Generating, LLC-IA	BACT	RBLC
0.05 lb/MMBtu	(4) GE 7FA	Low NOx	07/12/2002	Barton Shoals Energy, LLC_AL	BACT	RBLC
1.2 lb/hr, 0.036 lb/MMBtu	(4) GE 7FA	Good combustion	06/27/2002	Duke Energy Curry, LLC Clovis Energy Facility-NM	BACT	RBLC
0.035 lb/MMBtu	Not Listed	Low NOx	06/13/2002	Genova Oklahoma, LLC Genova OK I Power Project-OK	BACT	RBLC
0.075 lb/MMBtu	Not Listed	Low NOx	05/06/2002	Redbud Energy LP Redbud Power PLT-OK	BACT	RBLC
0.05 lb/MMBtu	Not Listed	Good combustion	04/10/2002	Midamerican Energy Greater Des Moines Energy Center-IA	BACT	RBLC
0.035 lb/MMBTu	(2) GE 7FA	Good combustion	04/01/2002	Duke Energy Duke Energy-Jackson Facility-AR	BACT	RBLC
0.1 lb/MMBtu	(4) GE LM600	Good combustion	02/12/2002	Mustang Power, LLC Horseshoe Energy Project-OK	BACT	RBLC
0.01 lb/MMBtu	(4) GE LM600	Good combustion	02/12/2002	Mustang Power, LLC Mustang Energy Project-OK	BACT	RBLC
4.07 lb/hr, 0.049 lb/ MMBtu	Not Listed	Low NOx	01/09/2002	Genpower Earleys, LLC-NC	BACT	RBLC

[1] Per permit review report. RBLC notes SCR , but as noted in the review report, this facility will achieve this limit via good combustion, not SCR.

Use of Low NOx burners, good combustion, and flue gas recirculation are the most common control technologies listed in the RBLC for auxiliary boilers. In each case, the auxiliary boilers are fueled solely by natural gas and appear to support turbine startup. Ultralow NOx burners were not found in the RBLC as a control technology for auxiliary boilers to support turbine startup. Of the various projects listed, the Entergy Hawkeye Facility located in Indiana appears to have the most stringent emission limit of 0.034 lb/MMBtu (issued to a 48.5 MMBtu/hr auxiliary boiler) using good combustion for NOx control. Additionally, the Genova Oklahoma I Power Project and the COB Energy Facility (Oregon) both have a 0.035 lb/MMBtu BACT limit using low-NOx burners.

Although it was not identified as a control technology employed for auxiliary boilers, selective catalytic reduction (SCR) was evaluated for the auxiliary boiler. The estimated cost for SCR NOx control is approximately $80,000 per ton of NOx removed (see Attachment A), and is therefore not cost-effective.
Low-NOx burners are therefore determined to reflect BACT for NOx control.

BACT for CO

A search of the RBLC database for natural gas-fired auxiliary boiler projects (maximum design input rating between 10 and 100 MMBtu/hr) permitted with CO limits is summarized in Table 2.

TABLE 2
Recent CO Limits for Natural Gas-Fired Auxiliary Boiler Projects for Combustion Turbines

Emission Limit	Turbine Equipment	Aux. Boiler Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER	Reference
0.037 lb/MMBtu	(4) GE 7FA	Good Combustion[2]	12/30/2003	Peoples Energy Resources COB Energy Facility, LLC-OR	BACT	RBLC/ DEQ Permit Review Report
0.093 lb/MMBtu	(2) GE 7FA	Good Combustion	03/24/2003	Genpower Rincon, LLC Rincon Power Plant-GA	BACT	RBLC
0.085 lb/MMBtu	(2) GE 7FA	Good Combustion	03/21/2003	Duke Energy Duke Energy Stephens, LLC-OK	BACT	RBLC
0.035 lb/MMBtu (3-hr ave.)	Not Listed	Good Combustion	03/12/2003	Klamath Generation, LLC-OR	BACT	RBLC
0.083 lb/MMBtu	(4) GE 7FA	Good Combustion	01/03/2003	Wallula Generation, LLC Wallula Power Plant-WA	BACT	RBLC
0.0164 lb/MMBtu	(2) GE 7FA	Catalytic Oxidation	12/20/2002	Interstate Power & Light Emery Generating Station-IA	BACT	RBLC
2.9 lb/hr, 0.073 lb/MMBtu	(4) GE 7FA	Good Combustion	11/21/2002	Cogentrix Energy Inc. Henry County Power-VA	BACT	RBLC
14.9 lb/hr, 0.15 lb/MMBtu	(2) GE 7FA	Good Combustion	11/18/2002	Virginia Power VA Power-Possum Point-VA	BACT	RBLC
0.037 lb/MMBtu	(4) GE 7FA	Good Combustion	10/23/2002	Duke Energy Murray, LLC Murray Energy Facility-GA	BACT	RBLC
6.42 lb/hr, 0.08 lb/MMBtu	Not Listed	Good Combustion	09/06/2002	Competitve Power Venture CPV Cunningham Creek-VA	BACT	RBLC
0.04 lb/MMBtu	Not Listed	Good Combustion	08/23/2002	Genova Arkansas I, LLC-AR	BACT	RBLC
0.073 lb/MMBtu	(2) GE 7FA	Good Combustion	07/23/2002	Entergy Hawkeye Generating, LLC-IA	BACT	RBLC
0.05 lb/MMBtu	(4) GE 7FA	Good Combustion	07/12/2002	Barton Shoals Energy, LLC_AL	BACT	RBLC
4.9 lb/hr, 0.07 lb/MMBtu	(4) GE 7FA	Good Combustion	06/27/2002	Duke Energy Curry, LLC Clovis Energy Facility-NM	BACT	RBLC
0.037 lb/MMBtu	Not Listed	Good Combustion	06/13/2002	Genova Oklahoma, LLC Genova OK I Power Project-OK	BACT	RBLC

[2] Per permit review report. RBLC notes catalytic oxidation, but as noted in the COB review report, this facility will achieve this limit via good combustion, not catalytic oxidation.

TABLE 2
Recent CO Limits for Natural Gas-Fired Auxiliary Boiler Projects for Combustion Turbines

Emission Limit	Turbine Equipment	Aux. Boiler Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER	Reference
0.07lb/MMBtu	Not Listed	Good Combustion	05/06/2002	Redbud Energy LP Redbud Power PLT-OK	BACT	RBLC
0.084 lb/MMBtu	Not Listed	Good Combustion	04/10/2002	Midamerican Energy Greater Des Moines Energy Center-IA	BACT	RBLC
0.15 lb/MMBTu	(2) GE 7FA	Good Combustion	04/01/2002	Duke Energy Duke Energy-Jackson Facility-AR	BACT	RBLC
0.084 lb/MMBtu	(4) GE LM600	Good Combustion	02/12/2002	Mustang Power, LLC Horseshoe Energy Project-OK	BACT	RBLC
0.084 lb/MMBtu	(4) GE LM600	Good Combustion	02/12/2002	Mustang Power, LLC Mustang Energy Project-OK	BACT	RBLC
6.84 lb/hr, 0.082 lb/ MMBtu	Not Listed	Good Combustion	01/09/2002	Genpower Earleys, LLC-NC	BACT	RBLC

The technically feasible control methods listed in the RBLC for controlling auxiliary boiler CO emissions are catalytic oxidation and good combustion. The only facility listed that utilizes catalytic oxidation for controlling CO emissions is the Indiana Interstate Power and Light Emery Generating facility. Of the various projects listed, this facility contains the most stringent BACT limit of 0.0164 lb/MMBtu using an oxidation catalyst. The lowest CO limit identified for units employing good combustion to control CO was 0.035 lb/MM Btu (Klamath Generation).

The cost for employing catalytic oxidation for controlling CO from the auxiliary boiler is estimated to be approximately $72,000 per ton of CO removed (see Attachment B), and is therefore not cost-effective.

Good combustion control is therefore determined to reflect BACT for CO control.

BACT for VOC

A database search of EPA's RBLC for natural gas-fired auxiliary boiler projects for VOCs is summarized in Table 3.

TABLE 3
Recent VOC Limits for Natural Gas-Fired Auxiliary Boiler Projects for Combustion Turbines

Emission Limit	Turbine Equipment	Aux. Boiler Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER	Reference
Not Listed	(4) GE 7FA	NA	12/30/2003	Peoples Energy Resources COB Energy Facility, LLC-OR	NA	RBLC/ DEQ Permit Review Report
0.004 lb/MMBtu	(2) GE 7FA	Good Combustion	03/24/2003	Genpower Rincon, LLC Rincon Power Plant-GA	BACT	RBLC
0.016 lb/MMBtu	(2) GE 7FA	Good Combustion	03/21/2003	Duke Energy Duke Energy Stephens, LLC-OK	BACT	RBLC
Not Listed	Not Listed	Good Combustion	03/12/2003	Klamath Generation, LLC-OR	NA	RBLC
Not Listed	(4) GE 7FA	Good Combustion	01/03/2003	Wallula Generation, LLC Wallula Power Plant-WA	NA	RBLC
0.0054 lb/MMBtu	(2) GE 7FA	Catalytic Oxidation	12/20/2002	Interstate Power & Light Emery Generating Station-IA	BACT	RBLC

Not Listed	(4) GE 7FA	Good Combustion	11/21/2002	Cogentrix Energy Inc. Henry County Power-VA	NA	RBLC
0.4 lb/hr 0.004 lb/MMBtu	(2) GE 7FA	Good Combustion	11/18/2002	Virginia Power VA Power-Possum Point-VA	BACT	RBLC
0.0127 lb/MMBtu	(4) GE 7FA	Good Combustion	10/23/2002	Duke Energy Murray, LLC Murray Energy Facility-GA	BACT	RBLC
0.42 lb/hr	Not Listed	Good Combustion	09/06/2002	Competitve Power Venture CPV Cunningham Creek-VA	BACT	RBLC
0.018 lb/MMBtu	Not Listed	Good Combustion	08/23/2002	Genova Arkansas I, LLC-AR	BACT	RBLC
0.005 lb/MMBtu	(2) GE 7FA	Good Combustion	07/23/2002	Entergy Hawkeye Generating, LLC-IA	BACT	RBLC
0.0054 lb/MMBtu	(4) GE 7FA	Good Combustion	07/12/2002	Barton Shoals Energy, LLC_AL	BACT	RBLC
0.5 lb/hr	(4) GE 7FA	Good Combustion	06/27/2002	Duke Energy Curry, LLC Clovis Energy Facility-NM	BACT	RBLC
0.016 lb/MMBtu	Not Listed	Good Combustion	06/13/2002	Genova Oklahoma, LLC Genova OK I Power Project-OK	BACT	RBLC
0.0075 lb/MMBtu	Not Listed	Good Combustion	05/06/2002	Redbud Energy LP Redbud Power PLT-OK	BACT	RBLC
Not Listed	Not Listed	Good Combustion	04/10/2002	Midamerican Energy Greater Des Moines Energy Center-IA	NA	RBLC
0.016 lb/MMBTu	(2) GE 7FA	Good Combustion	04/01/2002	Duke Energy Duke Energy-Jackson Facility-AR	BACT	RBLC
0.0055 lb/MMBtu	(4) GE LM600	Good Combustion	02/12/2002	Mustang Power, LLC Horseshoe Energy Project-OK	BACT	RBLC
0.0055 lb/MMBtu	(4) GE LM600	Good Combustion	02/12/2002	Mustang Power, LLC Mustang Energy Project-OK	BACT	RBLC
0.45 lb/hr, 0.0054 lb/ MMBtu	Not Listed	Good Combustion	01/09/2002	Genpower Earleys, LLC-NC	BACT	RBLC

The preferred control technology listed is good combustion. The only exception is the Interstate Power and Light Emery Generating Station located in Indiana. As previously mentioned, that is a facility that uses catalytic oxidation for control of CO emissions (a technology that is not cost-effective for CO control for this facility).

Good combustion control is therefore determined to reflect BACT for control of VOCs for this facility.

BACT for PM and PM_{10}

A database search of EPA's RBLC for natural gas-fired auxiliary boiler projects permitted with PM and PM_{10} limits are summarized in Table 4.

TABLE 4
Recent PM and PM_{10} Limits for Natural Gas-Fired Auxiliary Boiler Projects for Combustion Turbines

Emission Limit	Turbine Equipment	Aux. Boiler Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER	Reference
Not Listed	(4) GE 7FA	NA	12/30/2003	Peoples Energy Resources COB Energy Facility, LLC-OR	NA	RBLC/ DEQ Permit Review Report
0.0084 lb/MMBtu	(2) GE 7FA	Natural Gas, Good Combustion	03/24/2003	Genpower Rincon, LLC Rincon Power Plant-GA	BACT	RBLC
0.01 lb/MMBtu	(2) GE 7FA	Natural Gas	03/21/2003	Duke Energy Duke Energy Stephens, LLC-OK	BACT	RBLC

TABLE 4
Recent PM and PM_{10} Limits for Natural Gas-Fired Auxiliary Boiler Projects for Combustion Turbines

Emission Limit	Turbine Equipment	Aux. Boiler Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER	Reference
0.0042 lb/MMBtu	Not Listed	Natural Gas	03/12/2003	Klamath Generation, LLC-OR	BACT	RBLC
Not Listed	(4) GE 7FA	NA	01/03/2003	Wallula Generation, LLC Wallula Power Plant-WA	NA	RBLC
0.0075 lb/MMBtu	(2) GE 7FA	Natural Gas	12/20/2002	Interstate Power & Light Emery Generating Station-IA	BACT	RBLC
Not Listed	(4) GE 7FA	NA	11/21/2002	Cogentrix Energy Inc. Henry County Power-VA	NA	RBLC
0.7 lb/hr 0.007 lb/MMBtu	(2) GE 7FA	Natural Gas, Good Combustion	11/18/2002	Virginia Power VA Power-Possum Point-VA	BACT	RBLC
0.01 lb/MMBtu	(4) GE 7FA	Natural Gas, Good Combustion	10/23/2002	Duke Energy Murray, LLC Murray Energy Facility-GA	BACT	RBLC
0.58 lb/hr 0.007 lb/MMBtu	Not Listed	Natural Gas, Good Combustion	09/06/2002	Competitve Power Venture CPV Cunningham Creek-VA	BACT	RBLC
0.012 lb/MMBtu	Not Listed	Natural Gas, Good Combustion	08/23/2002	Genova Arkansas I, LLC-AR	BACT	RBLC
0.007 lb/MMBtu	(2) GE 7FA	Natural Gas, Good Combustion	07/23/2002	Entergy Hawkeye Generating, LLC-IA	BACT	RBLC
0.0075 lb/MMBtu	(4) GE 7FA	Natural Gas	07/12/2002	Barton Shoals Energy, LLC_AL	BACT	RBLC
0.3 lb/hr, 0.009 lb/MMBtu	(4) GE 7FA	Natural Gas, Good Combustion	06/27/2002	Duke Energy Curry, LLC Clovis Energy Facility-NM	BACT	RBLC
0.01 lb/MMBtu	Not Listed	Natural Gas, Good Combustion	06/13/2002	Genova Oklahoma, LLC Genova OK I Power Project-OK	BACT	RBLC
0.0053 lb/MMBtu	Not Listed	Good Combustion	05/06/2002	Redbud Energy LP Redbud Power PLT-OK	BACT	RBLC
0.0076 lb/MMBtu	Not Listed	Natural Gas	04/10/2002	Midamerican Energy Greater Des Moines Energy Center-IA	BACT	RBLC
0.01 lb/MMBTu	(2) GE 7FA	Natural Gas, Good Combustion	04/01/2002	Duke Energy Duke Energy-Jackson Facility-AR	BACT	RBLC
0.0076 lb/MMBtu	(4) GE LM600	Natural Gas (low Ash)	02/12/2002	Mustang Power, LLC Horseshoe Energy Project-OK	BACT	RBLC
Not Listed	(4) GE LM600	NA	02/12/2002	Mustang Power, LLC Mustang Energy Project-OK	NA	RBLC
0.62 lb/hr, 0.0075 lb/ MMBtu	Not Listed	Natural Gas, Good Combustion	01/09/2002	Genpower Earleys, LLC-NC	BACT	RBLC

Use of natural gas and good combustion are the only technically feasible control methods listed in the RBLC for controlling PM and PM_{10} emissions from natural gas-fired auxiliary boilers.

Good combustion control gas is therefore determined to reflect BACT for PM and PM_{10} control for this facility.

TABLE 4
Recent PM and PM_{10} Limits for Natural Gas-Fired Auxiliary Boiler Projects for Combustion Turbines

Emission Limit	Turbine Equipment	Aux. Boiler Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER	Reference
0.0042 lb/MMBtu	Not Listed	Natural Gas	03/12/2003	Klamath Generation, LLC-OR	BACT	RBLC
Not Listed	(4) GE 7FA	NA	01/03/2003	Wallula Generation, LLC Wallula Power Plant-WA	NA	RBLC
0.0075 lb/MMBtu	(2) GE 7FA	Natural Gas	12/20/2002	Interstate Power & Light Emery Generating Station-IA	BACT	RBLC
Not Listed	(4) GE 7FA	NA	11/21/2002	Cogentrix Energy Inc. Henry County Power-VA	NA	RBLC
0.7 lb/hr 0.007 lb/MMBtu	(2) GE 7FA	Natural Gas, Good Combustion	11/18/2002	Virginia Power VA Power-Possum Point-VA	BACT	RBLC
0.01 lb/MMBtu	(4) GE 7FA	Natural Gas, Good Combustion	10/23/2002	Duke Energy Murray, LLC Murray Energy Facility-GA	BACT	RBLC
0.58 lb/hr 0.007 lb/MMBtu	Not Listed	Natural Gas, Good Combustion	09/06/2002	Competitve Power Venture CPV Cunningham Creek-VA	BACT	RBLC
0.012 lb/MMBtu	Not Listed	Natural Gas, Good Combustion	08/23/2002	Genova Arkansas I, LLC-AR	BACT	RBLC
0.007 lb/MMBtu	(2) GE 7FA	Natural Gas, Good Combustion	07/23/2002	Entergy Hawkeye Generating, LLC-IA	BACT	RBLC
0.0075 lb/MMBtu	(4) GE 7FA	Natural Gas	07/12/2002	Barton Shoals Energy, LLC_AL	BACT	RBLC
0.3 lb/hr, 0.009 lb/MMBtu	(4) GE 7FA	Natural Gas, Good Combustion	06/27/2002	Duke Energy Curry, LLC Clovis Energy Facility-NM	BACT	RBLC
0.01 lb/MMBtu	Not Listed	Natural Gas, Good Combustion	06/13/2002	Genova Oklahoma, LLC Genova OK I Power Project-OK	BACT	RBLC
0.0053 lb/MMBtu	Not Listed	Good Combustion	05/06/2002	Redbud Energy LP Redbud Power PLT-OK	BACT	RBLC
0.0076 lb/MMBtu	Not Listed	Natural Gas	04/10/2002	Midamerican Energy Greater Des Moines Energy Center-IA	BACT	RBLC
0.01 lb/MMBTu	(2) GE 7FA	Natural Gas, Good Combustion	04/01/2002	Duke Energy Duke Energy-Jackson Facility-AR	BACT	RBLC
0.0076 lb/MMBtu	(4) GE LM600	Natural Gas (low Ash)	02/12/2002	Mustang Power, LLC Horseshoe Energy Project-OK	BACT	RBLC
Not Listed	(4) GE LM600	NA	02/12/2002	Mustang Power, LLC Mustang Energy Project-OK	NA	RBLC
0.62 lb/hr, 0.0075 lb/ MMBtu	Not Listed	Natural Gas, Good Combustion	01/09/2002	Genpower Earleys, LLC-NC	BACT	RBLC

Use of natural gas and good combustion are the only technically feasible control methods listed in the RBLC for controlling PM and PM_{10} emissions from natural gas-fired auxiliary boilers.

Good combustion control gas is therefore determined to reflect BACT for PM and PM_{10} control for this facility.

PRELIMINARY SCHEDULE FOR
REVIEW OF SITE CERTIFICATION APPLICATION
FOR FPL WEST COUNTY ENERGY CENTER
DOAH CASE NO. 05-XXXXEPP
OGC CASE NO. 05-XXXX
DEP FILE NO. PA 05-47

April 14, 2005	FPL files Site Certification Application (SCA) with DEP Siting Coordination Office (SCO)
April 21, 2005	SCO requests DOAH to appoint Administrative Law Judge (ALJ) and furnishes list of Agencies to Applicant & ALJ
April 28, 2005	ALJ appointed
April 29, 2005	SCO determines SCA is complete
May 6, 2005	FPL distributes the SCA. DEP files proposed schedule with ALJ, FMPA and Affected Agencies
May 13, 2005	FPL and DEP publish Notice of Application Filing
May 27, 2005	Tentative Date to file Notice of Land Use Hearing
June 3, 2005	DEP and other agencies submit sufficiency questions to SCO [schedule assumes agencies will ask for additional information regarding the SCA] Notice of Land Use Hearing
June 20, 2005	SCO issues written determination as to whether SCA is sufficient.
July 5, 2005	DEP and other reviewing agencies issue preliminary statements of issues
July 13, 2005	Tenative Date for Land Use hearing.
August 1, 2005	FPLA files responses to sufficiency questions [schedule assumes SCA is sufficient as of this date]
October 3, 2005	DEP and other reviewing agencies submit reports to SCO. DEP issues preliminary determination and draft PSD permit
November 10, 2005	SCO issues DEP's report and written analysis

December 26, 2005	FPL publishes notice of certification hearing
February XX, 2006	ALJ conducts certification hearing
February XX, 2006	Parties submit proposed recommended orders
April XX, 2006	ALJ issues recommended order
June XX, 2006	Hearing with Siting Board