THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

EI801-09-AR

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Florida Power Corporation	End of 2009/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________, we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) – The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent – The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Florida Power Corporation		02 Year/Period of Report End of 2009/Q4	
03 Previous Name and Date of Change *(if name changed during year)*		/ /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 299 First Avenue North, St. Petersburg, FL, 33701			
05 Name of Contact Person Cynthia S. Lee		06 Title of Contact Person Manager-Reg/Prop Accounting	
07 Address of Contact Person *(Street, City, State, Zip Code)* 299 First Avenue North, St. Petersburg, FL, 33701			
08 Telephone of Contact Person, *Including Area Code* (727) 820-5535	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission		10 Date of Report *(Mo, Da, Yr)* 12/31/2009

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Mark Mulhern 02 Title Chief Financial Officer	03 Signature Mark Mulhern	04 Date Signed *(Mo, Da, Yr)* 04/12/2010

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer	Jeffrey J. Lyash	1,950,396
2	(through July 5, 2009)		
3			
4	President and Chief Executive Officer	Vincent M. Dolan	662,843
5	(as of July 6, 2009)		
6			
7	Senior Vice President and Chief Financial Officer	Mark F. Mulhern	1,767,180
8			
9	Chairman	William D. Johnson	6,454,010
10			
11	Executive Vice President	John R. McArthur	1,706,299
12			
13	Senior Vice President , Power Operations	Paula J. Sims	1,873,640
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Schedule Page: 104 Line No.: 1 Column: a

Page 104 discloses the compensation of both individuals who served as the Chief Executive Officer (CEO) of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) during portions of the year ended December 31, 2009, along with the compensation of the individual who served as PEF's Chief Financial Officer and the three most highly compensated executive officers other than the CEO and CFO who were serving as executive officers as of December 31, 2009. These individuals were identified in accordance with Item 402 of Regulation S-K as promulgated by the Securities and Exchange Commission.

Schedule Page: 104 Line No.: 1 Column: c

Total compensation, including salary, for 2009 received by the CEOs, CFO and the other three most highly compensated executives is determined in accordance with Item 402 of Regulation S-K as promulgated by the Securities and Exchange Commission. Progress Energy, Inc.'s (Progress Energy) executive officers serve as officers and/or directors of its various subsidiaries, including PEF. They have multiple responsibilities within and provide various services to Progress Energy and its subsidiaries. The compensation of Progress Energy's executive officers is designed to cover the full range of services they provide to Progress Energy and its subsidiaries. It is not the policy of Progress Energy to allocate compensation paid to its executive officers among the various subsidiaries to which they provide services.

Schedule Page: 104 Line No.: 4 Column: a

See footnote at Line 1 Column A.

Schedule Page: 104 Line No.: 4 Column: c

See footnote at Line 1 Column C.

Schedule Page: 104 Line No.: 7 Column: a

See footnote at Line 1 Column A.

Schedule Page: 104 Line No.: 7 Column: c

See footnote at Line 1 Column C.

Schedule Page: 104 Line No.: 9 Column: a

See footnote at Line 1 Column A.

Schedule Page: 104 Line No.: 9 Column: c

See footnote at Line 1 Column C.

Schedule Page: 104 Line No.: 11 Column: a

See footnote at Line 1 Column A.

Schedule Page: 104 Line No.: 11 Column: c

See footnote at Line 1 Column C.

Schedule Page: 104 Line No.: 13 Column: a

See footnote at Line 1 Column A.

Schedule Page: 104 Line No.: 13 Column: c

See footnote at Line 1 Column C.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Vincent M. Dolan	P.O. Box 14042, St. Petersburg, FL 33701
2	President and Chief Executive Officer	
3		
4	Jeffrey J. Lyash	P.O. Box 14042, St. Petersburg, FL 33701
5	Executive Vice President, Corporate Development	
6		
7	John R. McArthur	P.O. Box 1551, Raleigh, NC 27602
8	Executive Vice President	
9		
10	Lloyd M. Yates	P.O. Box 1551, Raleigh, NC 27602
11		
12	William D. Johnson	P.O. Box 1551, Raleigh, NC 27602
13	Chairman	
14		
15	Michael A. Lewis	P.O. Box 14042, St. Petersburg, FL 33701
16	Senior Vice President, Energy Delivery	
17		
18	Mark F. Mulhern	P.O. Box 1551, Raleigh, NC 27602
19	Senior Vice President and Chief Financial Officer	
20		
21	Paula J. Sims	P.O. Box 1551, Raleigh, NC 27602
22	Senior Vice President, Power Operations	
23		
24	Frank A. Schiller	P.O. Box 1551, Raleigh, NC 27602
25	Senior Vice President, Compliance, and General Counsel	
26		
27	***Florida Power Corporation has no Executive Committee	
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 105 Line No.: 1 Column: a

Elected to the Board effective August 31, 2009.

Schedule Page: 105 Line No.: 10 Column: a

Removed from the Board effective April 1, 2009

Schedule Page: 105 Line No.: 24 Column: a

Elected to the Board effective April 1, 2009.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC No. 104 - Schedule 0S	ER09-1093-000
2	Third Revised Volume No. 6	ER08-105-000
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Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20090622-3020	05/01/2009	ER09-1093-000	Annual Cost Factors	FERC No. 104
2	200905180319	05/15/2009	ER09-1166-000	Annual update, informational filing	Third Revised Volume
3	200906010084	05/29/2009	ER09-1228-000	Formula rate revisions	Third Revised Volume
4	200911020111	10/30/2009	ER10-173-000	Settlement of annual update/formula	Third Revised Volume
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. CHANGES IN AND IMPORTANT ADDITIONS TO FRANCHISE RIGHTS

During the quarter ended March 31, 2009 there were no important changes or additions to Franchise Rights.

During the quarter ended June 30, 2009 there were no important changes or additions to Franchise Rights.

During the quarter ended September 30, 2009 there were no important changes or additions to Franchise Rights.

During the quarter ended December 31, 2009 there were no important changes or additions to Franchise Rights.

Florida Power Corporation remits a franchise fee to municipalities collected from customers based on 6% of the retail revenues for specific revenue classes within these cities having the franchise agreements and based on the provisions of the negotiated agreement.

2. ACQUISITION OF OWNERSHIP IN OTHER COMPANIES

None

3. PURCHASE OR SALE OF AN OPERATING UNIT OR SYSTEM

None

4. IMPORTANT LEASEHOLDS

None

5. IMPORTANT EXTENSION OR REDUCTION TO TRANSMISSION OR DISTRIBUTION SYSTEM

None

6. OBLIGATIONS INCURRED AS A RESULT OF ISSUANCE OF SECURITIES OR ASSUMPTIONS OF LIABILITIES OR GUARANTEES

During the quarter ended March 31st, 2009, Florida Power Corporation issued $864,166,000 and redeemed $1,104,566,000 in commercial paper. The weighted average yield issued during the period was 1.167%.

During the quarter ended June 30th, 2009, Florida Power Corporation issued $0.00 and redeemed $130,233,000.00 in commercial paper. The weighted average yield issued during the period was 0.00%.

During the quarter ended September 30, 2009, Florida Power Corporation issued $114,000,000.00 and redeemed $64,000,000.00 in commercial paper. The outstanding balance was $50,000,000.00. The weighted average yield issued during the period was 0.372%.

During the quarter ended December 31, Florida Power Corporation issued $0.00 and redeemed $50,000,000.00 in commercial paper. The outstanding balance was $0.00 and the weighted average yield issued during the period was 0.00%.

7. CHANGES IN ARTICLES OF INCORPORATION OR AMENDMENTS TO CHARTER.

None

8. STATE THE ESTIMATED ANNUAL EFFECT AND NATURE OF ANY IMPORTANT WAGE SCALE CHANGES

Effective March 30, 2009, non-bargaining unit employees received an average 2.69% merit increase. Wages will increase approximately $4 million per year.

Effective December 7, 2009, all bargaining unit employees received a 3% wage rate increase in accordance with the Memorandum of Agreement with the International Brotherhood of Electrical Workers. This includes temporary and part-time employees who were active employees or on leave. Wages will increase approximately $3.6 million per year.

9. LEGAL PROCEEDINGS

See Part II, Item 1. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Report on Form 10-Q for the quarter-ended March 31, 2009.

See Part II, Item 1. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Report on Form 10-Q for the quarter-ended June 30, 2009.

See Part II, Item 1. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Report on Form 10-Q for the quarter-ended September 30, 2009.

See Part I, Item 1 under "Environmental" in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Report on Form 10-K for the year-ended December 31, 2009.

10. DESCRIBE BRIEFLY ANY MATERIALLY IMPORTANT TRANSACTIONS OF THE RESPONDENT NOT DISCLOSED ELSEWHERE IN THIS REPORT

None

11. (Reserved)

12. IF CHANGES DURING YEAR APPEAR IN THE ANNUAL REPORT TO STOCKHOLDERS IN EVERY RESPECT, SUCH NOTES CAN BE INCLUDED

Not Applicable

13. DESCRIBE FULLY ANY CHANGES IN OFFICERS, DIRECTORS, MAJOR SECURITY HOLDERS AND VOTING POWERS OF THE REPONDENT

Officer Changes:

Elected - David B. Fountain, Assistant Secretary	April 30, 2009
Retired - Joel Y. Kamya, Vice President	April 1, 2009
Elected - Gayle S. Lanier, Vice President	April 30, 2009
Elected - Lee T. Mazzocchi - Vice President	April 30, 2009
Elected - Frank A. Schiller - Senior Vice President	April 1, 2009
Elected - Jon A. Franke, Vice President	May 4, 2009
Elected - Vincent M. Dolan, President and CEO	July 6, 2009
Elected - Jeffrey J. Lyash, Executive Vice President	July 17, 2009
Elected - Frank A. Schiller, Compliance Officer	November 16, 2009
Removed - Jeffrey J. Lyash, President and CEO	July 6, 2009
Removed - Jocelyn B. Thornton, Vice President	November 16, 2009
Removed - Mark A. Meyers, Vice President	November 16, 2009

Director Changes:	
Elected - Frank A. Schiller	April 1, 2009
Elected - Vincent M. Dolan	August 31, 2009
Removed - Lloyd M. Yates	April 1, 2009

14. IF RESPONDENT PARTICIPATES IN A CASH MANAGEMENT PROGRAM AND ITS PROPRIETARY CAPITAL RATIO IS LESS THAN 30 PERCENT, DESCRIBE SIGNIFICANT EVENTS OR TRANSACTIONS CAUSING THE PROPRIETARY CAPITAL RATIO TO BE LESS THAN 30 PERCENT, AND EXTENT TO WHICH THE RESPONDENT HAS AMOUNTS LOANED OR MONEY ADVANCED TO ITS PARENT, SUBSIDIARY OR AFFILIATED COMPANIES THROUGH A CASH MANAGEMENT PROGRAM. ADDITIONALLY DESCRIBE PLANS TO REGAIN AT LEAST 30 PERCENT PROPRIETARY RATIO.

Not Applicable.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	end of 2009/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	354,405,315	354,405,315
3	Preferred Stock Issued (204)	250-251	33,496,700	33,496,700
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		31,115	31,115
7	Other Paid-In Capital (208-211)	253	1,389,461,151	762,002,026
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	2,743,646,221	2,283,689,225
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	143	5,490
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	2,985,550	-601,322
16	Total Proprietary Capital (lines 2 through 15)		4,524,026,195	3,433,028,549
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,040,865,000	4,040,865,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	150,000,000	150,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		8,220,703	8,971,356
24	Total Long-Term Debt (lines 18 through 23)		4,182,644,297	4,181,893,644
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		207,656,610	215,895,932
27	Accumulated Provision for Property Insurance (228.1)		135,959,312	138,840,416
28	Accumulated Provision for Injuries and Damages (228.2)		19,570,899	19,648,095
29	Accumulated Provision for Pensions and Benefits (228.3)		356,892,549	457,509,498
30	Accumulated Miscellaneous Operating Provisions (228.4)		96,300,336	108,589,511
31	Accumulated Provision for Rate Refunds (229)		134,449	1,569,227
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		174,435,479	209,087,489
34	Asset Retirement Obligations (230)		368,964,611	348,978,715
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,359,914,245	1,500,118,883
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	370,633,000
38	Accounts Payable (232)		436,469,577	497,988,319
39	Notes Payable to Associated Companies (233)		221,024,825	72,530,642
40	Accounts Payable to Associated Companies (234)		61,813,574	55,214,051
41	Customer Deposits (235)		204,609,581	199,623,363
42	Taxes Accrued (236)	262-263	-99,172,450	-27,105,282
43	Interest Accrued (237)		72,383,228	51,185,725
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		14,787,041	15,594,322
48	Miscellaneous Current and Accrued Liabilities (242)		66,978,970	84,131,866
49	Obligations Under Capital Leases-Current (243)		8,239,322	7,659,787
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		334,997,309	589,633,299
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		174,435,479	209,087,489
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,147,695,498	1,708,001,603
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,632,137	1,581,949
57	Accumulated Deferred Investment Tax Credits (255)	266-267	6,960,512	11,506,508
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	23,320,396	42,341,531
60	Other Regulatory Liabilities (254)	278	253,029,417	154,333,815
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	3,757,590	4,083,000
63	Accum. Deferred Income Taxes-Other Property (282)		660,183,457	547,273,147
64	Accum. Deferred Income Taxes-Other (283)		587,646,357	649,870,342
65	Total Deferred Credits (lines 56 through 64)		1,536,529,866	1,410,990,292
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		12,750,810,101	12,234,032,971

Schedule Page: 112 Line No.: 42 Column: c

Debit balance is due to a timing difference between corporate estimated tax payments and accrued tax liability.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	5,250,621,713	4,730,890,488		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,261,691,813	3,524,816,908		
5	Maintenance Expenses (402)	320-323	211,820,795	196,504,237		
6	Depreciation Expense (403)	336-337	330,920,466	301,087,762		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	2,729,761	354,972		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	2,278,734	3,109,079		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-411,097	-411,097		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		1,234,778,290	187,315,450		
13	(Less) Regulatory Credits (407.4)		958,852,417	486,752,213		
14	Taxes Other Than Income Taxes (408.1)	262-263	347,094,510	309,321,940		
15	Income Taxes - Federal (409.1)	262-263	124,552,573	36,540,063		
16	- Other (409.1)	262-263	20,553,896	11,486,179		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	-40,789,823	1,042,755,413		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	-108,700,108	906,458,818		
19	Investment Tax Credit Adj. - Net (411.4)	266	-4,545,996	-5,940,000		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		18,381,829	17,222,582		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,658,903,442	4,230,952,457		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		591,718,271	499,938,031		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
						2
5,250,621,713	4,730,890,488					3
						4
3,261,691,813	3,524,816,908					5
211,820,795	196,504,237					6
330,920,466	301,087,762					7
2,729,761	354,972					8
2,278,734	3,109,079					9
-411,097	-411,097					10
						11
						12
1,234,778,290	187,315,450					13
958,852,417	486,752,213					14
347,094,510	309,321,940					15
124,552,573	36,540,063					16
20,553,896	11,486,179					17
-40,789,823	1,042,755,413					18
-108,700,108	906,458,818					19
-4,545,996	-5,940,000					20
						21
						22
						23
						24
18,381,829	17,222,582					25
4,658,903,442	4,230,952,457					26
591,718,271	499,938,031					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		591,718,271	499,938,031		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		21,420,987	18,475,162		
34	(Less) Expenses of Nonutility Operations (417.1)		11,352,887	11,336,227		
35	Nonoperating Rental Income (418)		-631,347	-519,341		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	143	5,490		
37	Interest and Dividend Income (419)		714,187	6,355,326		
38	Allowance for Other Funds Used During Construction (419.1)		91,216,283	94,850,807		
39	Miscellaneous Nonoperating Income (421)		5,754,583	3,218,619		
40	Gain on Disposition of Property (421.1)		899,067	5,222,570		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		108,021,016	116,272,406		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		822,181	822,181		
45	Donations (426.1)		7,465,280	7,752,585		
46	Life Insurance (426.2)		-5,623,798	8,665,921		
47	Penalties (426.3)			-1,355,072		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,301,607	3,035,620		
49	Other Deductions (426.5)		1,400,185	1,457,358		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,365,455	20,378,593		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	58,407	98,729		
53	Income Taxes-Federal (409.2)	262-263	696,329	2,458,048		
54	Income Taxes-Other (409.2)	262-263	-898,760	405,656		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	57,680,279	1,127		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	57,283,973	277,579		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		252,282	2,685,981		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		101,403,279	93,207,832		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		232,834,558	211,549,646		
63	Amort. of Debt Disc. and Expense (428)		5,079,383	5,111,017		
64	Amortization of Loss on Reaquired Debt (428.1)		1,363,109	4,142,098		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		2,755,141	1,247,195		
68	Other Interest Expense (431)		16,012,707	14,314,870		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		27,105,862	28,237,751		
70	Net Interest Charges (Total of lines 62 thru 69)		230,939,036	208,127,075		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		462,182,514	385,018,788		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		462,182,514	385,018,788		

Schedule Page: 114 Line No.: 4 Column: d

In 2008 several maintenance accounts were inadvertently included in the operation expense total in Line 4 of page 114. Below is a breakdown of which accounts were reclassed out of operation expense and into the maintenance expense total in Line 5 of page 114.

Account	Description	12/31/2008
5140001	FOS MAINT-ENVIRONMENTAL	4,326,171
5320001	NUC MAINT OF MISC NUC PLANT	19,187
5730001	TRANS MAINT-ENVIRONMENTAL	1,822,772
5980001	DISTRIB MAINT-ENVIRONMENTAL	22,764,959
9350REC	MAINT OF GEN PLT-PROJ SUPT NCR	5,450
9350003	DEFERRED ENVIRONMENTAL COSTS	(12,853,729)
		16,084,809

Schedule Page: 114 Line No.: 5 Column: d

In 2008 several maintenance accounts were inadvertently included in the operation expense total in Line 4 of page 114. Below is a breakdown of which accounts were reclassed out of operation expense and into the maintenance expense total in Line 5 of page 114.

Account	Description	12/31/2008
5140001	FOS MAINT-ENVIRONMENTAL	4,326,171
5320001	NUC MAINT OF MISC NUC PLANT	19,187
5730001	TRANS MAINT-ENVIRONMENTAL	1,822,772
5980001	DISTRIB MAINT-ENVIRONMENTAL	22,764,959
9350REC	MAINT OF GEN PLT-PROJ SUPT NCR	5,450
9350003	DEFERRED ENVIRONMENTAL COSTS	(12,853,729)
		16,084,809

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,283,689,224	1,900,565,502
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Unrealized tax benefit/expense		-713,514	(377,715)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-713,514	(377,715)
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		462,182,371	385,013,298
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock Dividends Declared		-1,511,860	(1,511,860)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,511,860	(1,511,860)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock Dividends Declared			
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,743,646,221	2,283,689,225
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,743,646,221	2,283,689,225
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		143	5,490
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		143	5,490

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	462,182,514	385,018,788
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	331,752,711	301,801,047
5	Amortization of Limited and Electric Plant, Nuclear Fuel, Load Mgmt	16,446,293	11,280,378
6	Amortization of Debt Premium, expense and loss on acquisition	6,041,580	8,976,930
7	Other: (Gain) Loss on sale of assets, Other Adjustments to Net Income	116,118,373	39,625,894
8	Deferred Income Taxes (Net)	68,306,597	136,020,143
9	Investment Tax Credit Adjustment (Net)	-4,545,996	-5,940,000
10	Net (Increase) Decrease in Receivables	-5,431,774	-32,917,365
11	Net (Increase) Decrease in Inventory	-60,284,433	-95,474,408
12	Net (Increase) Decrease in Allowances Inventory	33,047,952	-45,133,142
13	Net Increase (Decrease) in Payables and Accrued Expenses	-87,630,971	34,231,151
14	Net (Increase) Decrease in Other Regulatory Assets	249,786,806	-124,118,215
15	Net Increase (Decrease) in Other Regulatory Liabilities	41,445,254	-176,230,548
16	(Less) Allowance for Other Funds Used During Construction	91,216,282	94,850,807
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote): Change in Current Assets	190,270,054	-327,160,502
19	Change in Other, Net	-129,715,653	35,482,637
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,136,573,025	50,611,981
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,539,966,111	-1,647,324,254
27	Gross Additions to Nuclear Fuel	-78,484,365	-42,518,434
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-5,315,089	-5,946,120
30	(Less) Allowance for Other Funds Used During Construction	-91,216,282	-94,850,807
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,532,549,283	-1,600,938,001
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		11,958,135
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-100,075	-1,281,158
40	Contributions and Advances from Assoc. and Subsidiary Companies		148,850,125
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-1,540,466,939	-781,612,508
45	Proceeds from Sales of Investment Securities (a)	1,544,761,238	783,776,944

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,528,355,059	-1,439,246,463
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		1,475,346,736
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote): Increase in Intercompany Notes	148,719,245	72,276,387
65			
66	Net Increase in Short-Term Debt (c)		370,633,000
67	Other (provide details in footnote): Contribution from Parent	620,000,000	
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	768,719,245	1,918,256,123
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-531,905,994
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):Capital Lease Payments and Other	-6,825,399	-53,809
77			
78	Net Decrease in Short-Term Debt (c)	-370,633,000	
79	Other		
80	Dividends on Preferred Stock	-1,511,859	-1,511,859
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	389,748,987	1,384,784,461
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-2,033,047	-3,850,021
87			
88	Cash and Cash Equivalents at Beginning of Period	17,203,736	21,053,757
89			
90	Cash and Cash Equivalents at End of period	15,170,689	17,203,736

Schedule Page: 120 Line No.: 6 Column: c

Line 6, column (c) - $4,138,776 was reclassified in the prior year from Change in Other Regulatory Assets to Amortization of Debt Premium, Expense and Loss on Acquisition for consistency with current year presentation.

Schedule Page: 120 Line No.: 19 Column: b

Change in Other, Net includes the following:

Change in Other Assets and Deferred Debits:	$(132,204)
Change in Accrued Pension and Other Benefits:	(82,615,016)
Change in Other Liabilities and Deferred Credits:	(46,968,433)

Schedule Page: 120 Line No.: 19 Column: c

Change in Other, Net includes the following:

Change in Other Assets and Deferred Debits:	$(13,752,192)
Proceeds from the Termination of Interest Rate Hedges:	14,464,149
Change in Accrued Pension and Other Benefits:	(23,439,354)
Change in Other Liabilities and Deferred Credits:	58,210,034

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Florida Power Corp d/b/a Progress Energy Florida's (PEF) financial statements have been prepared in conformity with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. These requirements differ from generally accepted accounting principles related to the presentation of certain items including but not limited to (1) the reporting of amounts gross or net, (2) the classification of short-term and long-term portions of assets or liabilities, (3) the classification of transactions as operating or non-operating income, (4) the classification of cost of removal obligations and (5) the classification of restricted cash. Please refer to the 10-K footnotes attached below.

PEF's Notes to Financial Statements have been combined with Progress Energy, Inc. and Carolina Power and Light Company d/b/a Progress Energy Carolinas, Inc. and are prepared in conformity with generally accepted accounting principles. Accordingly, certain footnotes are not reflective of PEF's Financial Statements contained herein.

OTHER DISCLOSURES

Cash payments for interest and income taxes for the year ended December 31, 2009 were $228 million and $184 million, respectively.

PROGRESS ENERGY, INC.
CAROLINA POWER & LIGHT COMPANY d/b/a/ PROGRESS ENERGY CAROLINAS, INC.
FLORIDA POWER CORPORATION d/b/a/ PROGRESS ENERGY FLORIDA, INC.

COMBINED NOTES TO FINANCIAL STATEMENTS

In this report, Progress Energy, which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis, is at times referred to as "we," "us" or "our." When discussing Progress Energy's financial information, it necessarily includes the results of PEC and PEF (collectively, the Utilities). The term "Progress Registrants" refers to each of the three separate registrants: Progress Energy, PEC and PEF. The information in these combined notes relates to each of the Progress Registrants as noted in the Index to the Combined Notes. However, neither of the Utilities makes any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. ORGANIZATION

PROGRESS ENERGY, INC.

The Parent is a holding company headquartered in Raleigh, N.C. As such, we are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the regulatory provisions of the Public Utility Holding Company Act of 2005 (PUHCA 2005).

Our reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity. The Corporate and Other segment primarily includes amounts applicable to the activities of the Parent and Progress Energy Service Company (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable business segment. See Note 19 for further information about our segments.

PEC

PEC is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. PEC's subsidiaries are involved in insignificant nonregulated business activities. PEC is subject to the regulatory provisions of the North Carolina Utilities Commission (NCUC), Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC) and the FERC.

PEF

PEF is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in west central Florida. PEF is subject to the regulatory provisions of the Florida Public Service Commission (FPSC), the NRC and the FERC.

B. BASIS OF PRESENTATION

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP), including GAAP for regulated operations. The financial statements include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy, and as such their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements.

Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in noncontrolling interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for noncontrolling interests are reported on a net of tax basis if the underlying subsidiary is structured as a taxable entity.

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies, are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis. Other investments are stated principally at cost. These equity and cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. See Note 12 for more information about our investments.

Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by GAAP for regulated operations, which provides that profits on intercompany sales to regulated affiliates are not eliminated, if the sales price is reasonable and the future recovery of the sales price through the ratemaking process is probable.

Our presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under GAAP.

These combined notes accompany and form an integral part of Progress Energy's and PEC's consolidated financial statements and PEF's financial statements.

Certain amounts for 2008 and 2007 have been reclassified to conform to the 2009 presentation.

C. CONSOLIDATION OF VARIABLE INTEREST ENTITIES

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities (VIEs) for which we are the primary beneficiary. In general, we determine whether we are the primary beneficiary of a VIE through a qualitative analysis of risk that identifies which variable interest holder absorbs the majority of the financial risk and variability of the VIE. In performing this analysis, we consider all relevant facts and circumstances, including: the design and activities of the VIE, the terms of the contracts the VIE has entered into, the nature of the VIE's variable interests issued and how they were negotiated with or marketed to potential investors, and which parties participated significantly in the design or redesign of the entity. If the qualitative analysis is inconclusive, a specific quantitative analysis is performed.

In June 2009, the *Financial Accounting Standards Board (*FASB) issued new guidance which makes significant changes to the model for determining who should consolidate a VIE and addresses how often this assessment should be performed. See Note 2 for further discussion regarding the new guidance, which requires all existing arrangements with VIEs to be evaluated, and any impacts of adoption accounted for as a cumulative-effect adjustment. The guidance is effective for us on January 1, 2010. We do not expect the adoption to have a significant impact on our or the Utilities' financial position, results of operations and cash flows.

PROGRESS ENERGY

In addition to the following variable interests listed for PEC, Progress Energy, through its subsidiary Progress Fuels Corporation (Progress Fuels), is the primary beneficiary of, and consolidates, Ceredo Synfuel, LLC (Ceredo), a coal-based solid synthetic fuels production facility that qualified for federal tax credits under Section 45K of the Internal Revenue Code (the Code). In March 2007, we disposed of our 100 percent ownership interest in Ceredo to a third-party buyer. Ceredo ceased operations upon expiration of the synthetic fuels tax credit program at the end of 2007. Our variable interests in Ceredo are comprised of an agreement to operate the Ceredo facility on behalf of the buyer through December 2007 and certain legal and tax indemnifications provided to the buyer. We performed a qualitative analysis to determine the primary beneficiary of Ceredo. The primary factors in the analysis were the estimated levels of production of qualifying synthetic fuels in 2007, the final value of the related 2007 synthetic fuels tax credits, the likelihood of a full or partial phase-out of the 2007 synthetic fuels tax credits due to high oil prices, our exposure to certain variable costs under the facility operating agreement and exposure from indemnifications provided to the buyer. There were no changes to our assessment of the primary beneficiary during 2008 or 2009. No financial or other support has been provided to Ceredo during the periods presented. At December 31, 2009, we had no assets and $3 million of liabilities related to tax indemnifications provided to the buyer included in other liabilities and deferred credits on the Consolidated Balance Sheets. The ultimate resolution of the indemnifications could result in adjustments to the gain on disposal in future periods. The creditors of Ceredo do not have recourse to the general credit of Progress Energy. See Note 22C for a general discussion of guarantees. See Note 22D for discussion of recent developments related to legal indemnifications.

PEC

VARIABLE INTEREST ENTITIES FOR WHICH PEC IS THE PRIMARY BENEFICIARY

PEC is the primary beneficiary of, and consolidates, two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Internal Revenue Code (the Code). PEC's variable interests are debt and equity investments in the two VIEs. PEC performed quantitative analyses to determine the primary beneficiaries of the two VIEs. The primary factors in the analyses were the estimated economic lives of the partnerships and their net cash flow projections, estimates of available tax credits, and the likelihood of default on debt and other commitments. There were no changes to PEC's assessment of the primary beneficiary during 2007 through 2009. No financial or other support has been provided to the VIEs during the periods presented. At December 31, 2009, PEC had assets of $39 million, substantially all of which was reflected in miscellaneous other property and investment, and $15 million in long-term debt, $3 million in other liabilities and deferred credits and $5 million in accounts payable in the PEC Consolidated Balance Sheets related to the two VIEs. The assets of the two VIEs are collateral for, and can only be used to settle, their obligations. The creditors of these VIEs do not have recourse to the general credit of PEC and there are no other arrangements that could expose PEC to losses.

OTHER VARIABLE INTERESTS

PEC has an equity investment in, and consolidates, one limited partnership investment fund that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. The investment fund accounts for the 17 partnerships on the equity method of accounting. PEC also has an interest in one power plant resulting from long-term power purchase contracts. PEC's only significant exposure to variability from the power purchase contracts results from fluctuations in the market price of fuel used by the entity's plants to produce the power purchased by PEC. We are able to recover these fuel costs under PEC's fuel clause. Total purchases from this counterparty were $46 million, $44 million and $39 million in 2009, 2008 and 2007, respectively. The generation capacity of the entity's power plant is approximately 847 megawatts (MW). PEC has requested the necessary information to determine if the investment fund's 17 partnerships and the power plant owner are VIEs or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC, and, accordingly, PEC has applied the information scope exception provided by GAAP to the 17 partnerships and the power plant. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the power plant and the investment fund consolidating the 17 partnerships would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparties, the impact cannot be determined at this time.

PEF

PEF has no significant variable interests in VIEs.

D. SIGNIFICANT ACCOUNTING POLICIES

USE OF ESTIMATES AND ASSUMPTIONS

In preparing consolidated financial statements that conform to GAAP, management must make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and amounts of revenues and expenses reflected during the reporting period. Actual results could differ from those estimates.

REVENUE RECOGNITION

We recognize revenue when it is realized or realizable and earned when all of the following criteria are met: persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; our price to the buyer is fixed or determinable; and collectability is reasonably assured. We recognize electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utility base revenues earned when service has been delivered but not billed by the end of the accounting period. Customer prepayments are recorded as deferred revenue and recognized as revenues as the services are provided.

FUEL COST DEFERRALS

Fuel expense includes fuel costs and other recoveries that are deferred through fuel clauses established by the Utilities' regulators. These clauses allow the Utilities to recover fuel costs, fuel-related costs and portions of purchased power costs through surcharges on customer rates. These deferred fuel costs are recognized in revenues and fuel expenses as they are billable to customers.

EXCISE TAXES

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for sales and use tax on a net basis and gross receipts tax, franchise taxes and other excise taxes on a gross basis.

The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income in the statements of income for the years ended December 31 were as follows:

(in millions)	**2009**	2008	2007
Progress Energy	**$333**	$295	$299
PEC	**108**	102	99
PEF	**225**	193	200

STOCK-BASED COMPENSATION

As discussed in Note 9B, we account for stock-based compensation utilizing the modified prospective transition method per the fair value recognition provisions of GAAP.

RELATED PARTY TRANSACTIONS

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with PUHCA 2005. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. In the subsidiaries' financial statements, billings from affiliates are capitalized or expensed depending on the nature of the services rendered.

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs of units of property as well as indirect construction costs. Certain costs are capitalized in accordance with regulatory treatment. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property (including planned major maintenance activities), and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred, with the exception of nuclear outages at PEF. Pursuant to a regulatory order, PEF accrues for nuclear outage costs in advance of scheduled outages, which occur every two years. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal or disposal costs that do not represent asset retirement obligations (AROs) are charged to a regulatory liability.

Allowance for funds used during construction (AFUDC) represents the estimated costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform system of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges.

Nuclear fuel is classified as a fixed asset and included in the utility plant section of the Balance Sheets. Nuclear fuel in the front-end fuel processing phase is considered work in progress and not amortized until placed in service.

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

Substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 4A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization rates of utility assets (See Note 7).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method. In the Utilities' retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC, the SCPSC and the FPSC and are based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdictions, the provisions for nuclear decommissioning costs are approved by the FERC.

The North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in 2002 and froze North Carolina electric utility base rates for a five-year period, which ended in December 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation. During the rate freeze period, the legislation provided for the amortization and recovery of 70 percent of the original estimated compliance costs for the Clean Smokestacks Act while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. In September 2008, the NCUC approved PEC's request to terminate any further accelerated amortization of its Clean Smokestacks compliance costs (See Note 7B).

ASSET RETIREMENT OBLIGATIONS

AROs are legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability. Accretion expense is included in depreciation, amortization and accretion in the Consolidated Statements of Income.

CASH AND CASH EQUIVALENTS

We consider cash and cash equivalents to include unrestricted cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

INVENTORY

We account for inventory, including emission allowances, using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. Materials reserves are established for excess and obsolete inventory.

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to GAAP for regulated operations, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, the Utilities record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 7A). The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

NUCLEAR COST DEFERRALS

PEF accounts for costs incurred in connection with the proposed nuclear expansion in Florida in accordance with FPSC regulations, which establish an alternative cost-recovery mechanism. PEF is allowed to accelerate the recovery of prudently incurred siting, preconstruction costs, AFUDC and incremental operation and maintenance expenses resulting from the siting, licensing, design and construction of a nuclear plant through PEF's capacity cost-recovery clause. Nuclear costs are deemed to be recovered up to the amount of the FPSC-approved projections, and the deferral of unrecovered nuclear costs accrues a carrying charge equal to PEF's approved AFUDC rate. Unrecovered nuclear costs eligible for accelerated recovery are deferred and recorded as regulatory assets in the Consolidated Balance Sheets and are amortized in the period the costs are collected from customers.

GOODWILL AND INTANGIBLE ASSETS

Goodwill is subject to at least an annual assessment for impairment by applying a two-step, fair value-based test. This assessment could result in periodic impairment charges. Intangible assets are amortized based on the economic benefit of their respective lives.

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

Long-term debt premiums, discounts and issuance expenses are amortized over the terms of the debt issues. Any expenses or call premiums associated with the reacquisition of debt obligations by the Utilities are amortized over the applicable lives using the straight-line method consistent with ratemaking treatment (See Note 7A).

INCOME TAXES

We and our affiliates file a consolidated federal income tax return. The consolidated income tax of Progress Energy is allocated to PEC and PEF in accordance with the Intercompany Income Tax Allocation Agreement (Tax Agreement). The Tax Agreement provides an allocation that recognizes positive and negative corporate taxable income. The Tax Agreement provides for an equitable method of apportioning the carryover of uncompensated tax benefits, which primarily relate to deferred synthetic fuels tax credits. Income taxes are provided for as if PEC and PEF filed separate returns.

Deferred income taxes have been provided for temporary differences. These occur when the book and tax carrying amounts of assets and liabilities differ. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. Credits for the production and sale of synthetic fuels are deferred credits to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns, and are included in income tax expense (benefit) of discontinued operations in the Consolidated Statements of Income. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority, including resolutions of any related appeals or litigation processes, based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount of the tax benefit that, in our judgment, is greater than 50 percent likely to be realized. Interest expense on tax deficiencies and uncertain tax positions is included in net interest charges, and tax penalties are included in other, net in the Consolidated Statements of Income.

DERIVATIVES

GAAP requires that an entity recognize all derivatives as assets or liabilities on the balance sheet and measure those instruments at fair value, unless the derivatives meet the GAAP criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related hedge criteria are met. We have elected not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. Certain economic derivative instruments receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. See Note 17 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies, such as unfavorable results of litigation, when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. We do not accrue an estimate of legal fees when a contingent loss is initially recorded, but rather when the legal services are actually provided.

As discussed in Note 21, we accrue environmental remediation liabilities when the criteria for loss contingencies have been met. We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable or on actual receipt of recovery. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

We review the recoverability of long-lived tangible and intangible assets whenever impairment indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an impairment indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

We review our equity investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. We consider various factors, such as the investee's cash position, earnings and revenue outlook, liquidity and management's ability to raise capital in determining whether the decline is other-than-temporary. If we determine that an other-than-temporary decline in value exists, the investments are written down to fair value with a new cost basis established.

2. NEW ACCOUNTING STANDARDS

Effective July 1, 2009, changes to the source of authoritative U.S. GAAP, the *Financial Accounting Standards Board (FASB)*

Accounting Standards Codification (ASC), are communicated through an Accounting Standards Update (ASU). ASUs will be published for all authoritative U.S. GAAP promulgated by the FASB, regardless of the form in which such guidance may have been issued prior to release of the FASB Codification (e.g., FASB Statements, FASB Staff Positions, etc.).

ASC 810 Consolidations

On January 1, 2009, we implemented ASC 810-10-65, which was previously referred to as Statement of Financial Accounting Standards (SFAS) No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51." ASC 810-10-65 introduces significant changes in the accounting for noncontrolling interests in a partially owned consolidated subsidiary. The adoption of ASC 810-10-65 resulted in a retrospective change in presentation of the financial statements for all periods presented and additional disclosures but did not have a material impact on our or the Utilities' financial position or results of operations.

In June 2009, the FASB issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities." In January 2010, the FASB issued ASU 2009-17, "Consolidations (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities," which codified SFAS No. 167. This guidance makes significant changes to the model for determining who should consolidate a VIE, addresses how often this assessment should be performed, requires all existing arrangements with VIEs to be evaluated, and must be adopted through a cumulative-effect adjustment. This guidance is effective for us on January 1, 2010. See Note 1C for information regarding our implementation of ASU 2009-17 and its expected impact on our financial position and results of operations.

ASC 815-10-65 (SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133)"

On January 1, 2009, we implemented ASC 815-10-65, which was previously referred to as SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133." ASC 815-10-65 requires entities to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and its related interpretations and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. See Note 17 for information regarding our first quarter 2009 implementation of ASC 815-10-65. The adoption of ASC 815-10-65 did not have a material impact on our or the Utilities' financial position or results of operations.

ASC 260-10-45 (FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities)"

On January 1, 2009, we implemented ASC 260-10-45, which was previously referred to as FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities." ASC 260-10-45 requires that certain unvested share-based payment awards (e.g., restricted stock) that contain nonforfeitable rights to dividends or dividend equivalents be included in the computation of earnings per share using the two-class method. ASC 260-10-45 requires a retrospective adjustment for all prior-period earnings per share data. The adoption of ASC 260-10-45 did not have a material impact on our or the Utilities' financial position, results of operations or earnings per share amounts.

Fair Value Measurement and Disclosures and Other-Than-Temporary Impairments

In April 2009, the FASB issued three FSPs for guidance on accounting for fair value measurement and other-than-temporary impairments.

ASC 820 includes the FSP previously referred to as FSP FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly," and provides guidance on determining fair value when market activity has decreased for an asset or liability. ASC 825-10-50, previously referred to as FSP FAS 107-1 and APB 28-1, "Interim Disclosures About Fair Value of Financial Instruments," increases the frequency of fair value disclosures required from annually to quarterly.

ASC 320 includes the FSPs previously referred to as FSP FAS 115-2 and FAS 124-2, "Recognition and Presentation of Other-Than-Temporary Impairments," and revises the recognition and reporting requirements for other-than-temporary impairments of debt securities and increases the frequency of disclosures for debt and equity securities. Under ASC 320, if an entity intends to sell an impaired debt security or more likely than not will be required to sell the security before recovery of its amortized cost basis less any current-period credit loss, an other-than-temporary impairment must be recognized currently in earnings equal to the difference between the investment's amortized cost and its fair value at the balance sheet date.

The new guidance in ASC 820, ASC 825 and ASC 320 was effective for us during the three months ended June 30, 2009. The adoption resulted in additional disclosures but did not have a material impact on our or the Utilities' financial position or results of operations. See Note 13 for the disclosures resulting from the implementation of this guidance in 2009.

In January 2010, the FASB issued ASU 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," which amends ASC 820 to clarify certain existing disclosure requirements and to require a number of additional disclosures, including amounts and reasons for significant transfers between the three levels of the fair value hierarchy, and presentation of certain information in the reconciliation of recurring Level 3 measurements on a gross basis. ASU 2010-06 is effective for us on January 1, 2010, with certain disclosures effective for periods beginning January 1, 2011. The adoption of ASU 2010-06 will change certain disclosures in the notes to the financial statements, but will have no impact on our or the Utilities' financial position or results of operations.

ASC 715-20-65 (FSP FAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets")

In December 2008, the FASB issued ASC 715-20-65, previously referred to as FSP FAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets," which requires additional disclosures on the investment allocation decision making process, the fair value of each major category of plan assets and the inputs and valuation techniques used to remeasure the fair value of plan assets. ASC 715-20-65 was effective for us on December 31, 2009. The adoption of ASC 715-20-65 resulted in additional disclosures, but did not have a material impact on our or the Utilities' financial position or results of operations. See Note 16 for the information regarding our implementation of ASC 715-20-65.

ASU 2009-12, "Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)"

In September 2009, the FASB issued ASU 2009-12, "Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)," which provides additional guidance related to measuring the fair value of certain alternative investments, such as interests in hedge funds, private equity funds, real estate funds, venture capital funds, offshore fund vehicles, and funds of funds. ASU 2009-12 allows reporting entities to use net asset value per share to estimate the fair value of certain investments as a practical expedient and requires disclosures by major category of investment about the attributes of the investments. ASU 2009-12 was effective for us on December 31, 2009. The adoption of ASU 2009-12 did not have a material impact on our or the Utilities' financial position or results of operations.

3. DIVESTITURES

We completed our business strategy of divesting nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. The information below presents the impacts of the divestitures on net income attributable to controlling interests.

A. TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

On March 7, 2008, we sold coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. Proceeds from the sale were used for general corporate purposes. During the year ended December 31, 2008, we recorded an after-tax gain of $42 million on the sale of these assets. The accompanying consolidated financial statements reflect the operations of

Terminals as discontinued operations.

Prior to 2008, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 (Section 29) of the Code and as redesignated effective 2006 as Section 45K of the Code (Section 45K and, collectively, Section 29/45K). The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007.

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates. As a result, during the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations, which was net of a previously recorded indemnification liability of $16 million, and $4 million related to other legal and tax contingency adjustments. The ultimate resolution of these matters could result in further adjustments. See Note 22D for additional information. The accompanying consolidated statements of income reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Results of Terminals and the synthetic fuels businesses discontinued operations for the years ended December 31 were as follows:

(in millions)	2009	2008	2007
Revenues	$–	$17	$1,126
(Loss) earnings before income taxes and noncontrolling interest	$(125)	$8	$2
Income tax benefit, including tax credits	47	12	64
(Loss) earnings attributable to noncontrolling interests of Synthetic Fuels	–	(1)	17
Net (loss) earnings from discontinued operations attributable to controlling interests	(78)	19	83
Gain on disposal of discontinued operations, including income tax expense of $7	–	42	–
(Loss) earnings from discontinued operations attributable to controlling interests	$(78)	$61	$83

B. COAL MINING BUSINESSES

On March 7, 2008, we sold the remaining operations of Progress Fuels Corporation, formerly Electric Fuels Corporation (Progress Fuels) subsidiaries engaged in the coal mining business (Coal Mining) for gross cash proceeds of $23 million. Proceeds from the sale were used for general corporate purposes. As a result of the sale, during the year ended December 31, 2008, we recorded an after-tax gain of $7 million on the sale of these assets. During 2009, we recognized a $1 million loss as a result of post-closing adjustments and pre-divestiture contingencies.

The accompanying consolidated financial statements reflect the Coal Mining as discontinued operations. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

(in millions)	**2009**	2008	2007
Revenues	**$–**	$2	$28
Loss before income taxes	**$(2)**	$(13)	$(17)
Income tax benefit	**1**	4	6
Net loss from discontinued operations	**(1)**	(9)	(11)
Gain on disposal of discontinued operations, including income tax expense of $2	–	7	–
Loss from discontinued operations attributable to controlling interests	**$(1)**	$(2)	$(11)

C. CCO – GEORGIA OPERATIONS

On March 9, 2007, our subsidiary, Progress Energy Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. Based on the terms of the final agreement and post-closing adjustments, during the years ended December 31, 2008 and 2007, we incurred an additional $2 million after-tax in losses and reversed $18 million after-tax of a previously recorded impairment, respectively.

Additionally, on June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of full-requirements contracts with 16 Georgia electric membership cooperatives (the Georgia Contracts), forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represented substantially all of our nonregulated energy marketing and trading operations. As a result of the assignments, PVI made a net cash payment of $347 million, which represented the net cost to assign the Georgia Contracts and other related contracts. In the year ended December 31, 2007, we recorded a charge associated with the costs to exit the Georgia Contracts, and other related contracts, of $349 million after-tax (charge included in the net loss from discontinued operations in the table below). We used the net proceeds from the divestiture of CCO and the Georgia Contracts for general corporate purposes. During 2008 and 2009, we recognized a $5 million loss and a $1 million gain, respectively, as a result of post-closing adjustments and pre-divestiture contingencies.

The accompanying consolidated financial statements reflect the operations of CCO as discontinued operations. Interest expense was allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the year ended December 31, 2007, was $11 million. Results of discontinued operations for CCO for the years ended December 31 were as follows:

(in millions)	**2009**	2008	2007
Revenues	**$–**	$–	$407
Loss before income taxes	**$(1)**	$(5)	$(449)
Income tax benefit	**2**	2	166
Net earnings (loss) from discontinued operations	**1**	(3)	(283)
(Loss) gain on disposal of discontinued operations, including income tax (expense) benefit of $(2) and $7, respectively	–	(2)	18
Earnings (loss) from discontinued operations attributable to controlling interests	**$1**	$(5)	$(265)

D. OTHER DIVERSIFIED BUSINESSES

Also included in discontinued operations are amounts related to adjustments of our prior sales of other diversified businesses, primarily Progress Rail Services Corporation. We completed the sale of Progress Rail Services Corporation during the year ended December 31, 2005. As a result of certain legal, tax and environmental indemnifications provided by Progress Fuels and Progress Energy, we continue to record adjustments to the loss on sale. During the year ended December 31, 2009, we recorded an after-tax loss on disposal of $1 million and after-tax gains of $3 million and $4 million for the years ended December 31, 2008 and 2007, respectively. The ultimate resolution of these matters could result in additional adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

E. CEREDO SYNTHETIC FUELS INTERESTS

On March 30, 2007, our Progress Fuels subsidiary disposed of its 100 percent ownership interest in Ceredo, a subsidiary that produced and sold qualifying coal-based solid synthetic fuels, to a third-party buyer. In addition, we entered into an agreement to operate the Ceredo facility on behalf of the buyer. At closing, we received cash proceeds of $10 million and a nonrecourse note receivable of $54 million. Payments on the note were received as we produced and sold qualifying coal-based solid synthetic fuels on behalf of the buyer. In accordance with the terms of the agreement, we received payments on the note related to 2007 production of $49 million during the year ended December 31, 2007, and a final payment of $5 million during the year ended December 31, 2008. The note had an interest rate equal to the three-month London Inter Bank Offered Rate (LIBOR) rate plus 1%. The estimated fair value of the note at the inception of the transaction was $48 million. Under the terms of the agreement, the purchase price was reduced by $7 million during the year ended December 31, 2008, based on the final value of the 2007 Section 29/45K tax credits.

During the year ended December 31, 2008, we recognized previously deferred gains on disposal of $5 million based on the final value of the 2007 Section 29/45K tax credits. The operations of Ceredo ceased as of December 31, 2007, and are recorded as discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3A.

On the date of the transaction, the carrying value of the disposed ownership interest totaled $37 million, which consisted primarily of the fair value of crude oil call options purchased in January 2007. Subsequent to the disposal, we remain the primary beneficiary of Ceredo and continue to consolidate Ceredo in accordance with GAAP for variable interest entities, but record a 100 percent noncontrolling interest.

4. PROPERTY, PLANT AND EQUIPMENT

A. UTILITY PLANT

The balances of electric utility plant in service at December 31 are listed below, with a range of depreciable lives (in years) for each:

(in millions)	Depreciable Lives	Progress Energy 2009	Progress Energy 2008	PEC 2009	PEC 2008	PEF 2009	PEF 2008
Production plant	7-43	**$16,042**	$14,117	**$9,579**	$9,249	**6,280**	$4,689
Transmission plant	17-75	**3,273**	2,970	**1,535**	1,457	**1,738**	1,513
Distribution plant	13-55	**8,376**	8,028	**4,499**	4,330	**3,877**	3,698
General plant and other	5-35	**1,227**	1,211	**684**	662	**543**	549
Utility plant in service		**$28,918**	$26,326	**$16,297**	$15,698	**$12,438**	$10,449

Generally, electric utility plant at PEC and PEF, other than nuclear fuel, is pledged as collateral for the first mortgage bonds of PEC and PEF, respectively (See Note 11).

AFUDC represents the estimated costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant for certain projects in accordance with the regulatory provisions for each jurisdiction. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 9.2%, 9.2% and 8.8% in 2009, 2008 and 2007, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8% in 2009, 2008 and 2007.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4%, 2.3% and 2.4% in 2009, 2008 and 2007, respectively. The depreciation provisions related to utility plant were $626 million, $578 million and $560 million in 2009, 2008 and 2007, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4C), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 7B).

PEC's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.1% for 2009, 2008 and 2007. The depreciation provisions related to utility plant were $328 million, $310 million and $303 million in 2009, 2008 and 2007, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4C), regulatory approved expenses (See Note 7B) and Clean Smokestacks Act amortization (See Note 7B).

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.7% in 2009, 2008 and 2007. The depreciation provisions related to utility plant were $299 million, $268 million and $257 million in 2009, 2008 and 2007, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4C) and regulatory approved expenses (See Note 7C).

Nuclear fuel, net of amortization at December 31, 2009 and 2008, was $554 million and $482 million, respectively, for Progress Energy, $396 million and $376 million, respectively, for PEC and $158 million and $106 million, respectively, for PEF. The amount not yet in service at December 31, 2009 and 2008, was $308 million and $243 million, respectively, for Progress Energy, $175 million and $182 million, respectively, for PEC and $133 million and $61 million, respectively, for PEF. Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, was $159 million, $145 million and $139 million for the years ended December 31, 2009, 2008 and 2007, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income. Amortization of nuclear fuel costs for the years ended December 31, 2009, 2008 and 2007 was $134 million, $115 million and $110 million, respectively, for PEC and $25 million, $30 million and $29 million, respectively, for PEF.

PEF's construction work in progress related to certain nuclear projects has received regulatory treatment. At December 31, 2009, PEF reflected $296 million of construction work in progress, of which $274 million was reflected as a nuclear cost-recovery clause regulatory asset (See Note 7C) and $22 million was reflected as a deferred fuel regulatory asset. At December 31, 2008, PEF reflected $174 million of construction work in progress as a regulatory asset pursuant to accelerated regulatory recovery of nuclear costs (See Note 7C).

B. JOINT OWNERSHIP OF GENERATING FACILITIES

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs (See Note 21B). Each of the Utilities' share of operating costs of the jointly owned generating facilities is included within the corresponding line in the Statements of Income. The co-owner of Intercession City Unit P11 has exclusive rights to the output of the unit during the months of June through September. PEF has that right for the remainder of the year. PEC's and PEF's ownership interests in the jointly owned generating facilities are listed below with related information at December 31:

2009 (in millions) Subsidiary	**Facility**	**Company Ownership Interest**	**Plant Investment**	**Accumulated Depreciation**	**Construction Work in Progress**
PEC	**Mayo**	**83.83%**	**$785**	**$282**	**$8**
PEC	**Harris**	**83.83%**	**3,207**	**1,651**	**28**
PEC	**Brunswick**	**81.67%**	**1,681**	**981**	**74**
PEC	**Roxboro Unit 4**	**87.06%**	**686**	**449**	**15**
PEF	**Crystal River Unit 3**	**91.78%**	**900**	**472**	**510**
PEF	**Intercession City Unit P11**	**66.67%**	**23**	**10**	**–**

2008 (in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$519	$278	$228
PEC	Harris	83.83%	3,187	1,603	21
PEC	Brunswick	81.67%	1,667	970	42
PEC	Roxboro Unit 4	87.06%	674	446	12
PEF	Crystal River Unit 3	91.78%	843	461	252
PEF	Intercession City Unit P11	66.67%	23	9	–

In the tables above, plant investment and accumulated depreciation are not reduced by the regulatory disallowances related to the Shearon Harris Nuclear Plant (Harris), which are not applicable to the joint owner's ownership interest in Harris.

C. ASSET RETIREMENT OBLIGATIONS

Primarily due to the impact of updated cost estimates, as discussed below, at December 31, 2009, PEC had no asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant. At December 31, 2008, PEC's asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant, net of accumulated depreciation totaled $28 million. At December 31, 2009 and 2008, PEF's asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $18 million and $19 million, respectively. At December 31, 2009 and 2008, additional PEF-related asset retirement costs, net of accumulated depreciation, of $114 million and $116 million, respectively, were recorded at Progress Energy as purchase accounting adjustments recognized when we purchased Florida Progress Corporation (Florida Progress) in 2000. The fair value of funds set aside in the Utilities' NDT funds for the nuclear decommissioning liability totaled $871 million and $672 million at December 31, 2009 and 2008, respectively, for PEC and $496 million and $417 million, respectively, for PEF (See Notes 12 and 13). Net NDT unrealized gains are included in regulatory liabilities (See Note 7A).

PEC's nuclear decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2009, 2008 and 2007. As discussed below, PEF has suspended its accrual for nuclear decommissioning. Management believes that nuclear decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that do not meet the definition of AROs, which are included in depreciation, amortization and accretion expense, were $106 million, $100 million and $96 million in 2009, 2008 and 2007, respectively, for PEC and $35 million, $33 million and $30 million in 2009, 2008 and 2007, respectively, for PEF.

During 2009, PEF submitted a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study is expected to have an insignificant impact on cost of removal expense in 2010.

The Utilities recognize removal, nonirradiated decommissioning and dismantlement of fossil generation plant costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 7A). At December 31, such costs consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Removal costs	**$1,532**	$1,478	**$944**	$864	**$588**	$614
Nonirradiated decommissioning costs	**211**	146	**150**	84	**61**	62
Dismantlement costs	**123**	124	–	–	**123**	124
Non-ARO cost of removal	**$1,866**	$1,748	**$1,094**	$948	**$772**	$800

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC received a new site-specific estimate of decommissioning costs for Robinson Nuclear Plant (Robinson) Unit No. 2, Brunswick Nuclear Plant (Brunswick) Units No. 1 and No. 2, and Harris Nuclear Plant (Harris) Unit No. 1, in December 2009, which will be filed with the NCUC in the first quarter of 2010. PEC's estimate is based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2009 dollars, were $687 million for Unit No. 2 at Robinson, $591 million for Brunswick Unit No. 1, $585 million for Brunswick Unit No. 2 and $1.126 billion for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. See Note 7D for information about the NRC operating licenses held by PEC. Based on updated cost estimates, in 2009 PEC reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $27 million and $390 million, respectively, resulting in no asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant at December 31, 2009.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF received a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) in October 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing (See Note 7C). However, the FPSC deferred review of PEF's nuclear decommissioning study from the rate case to be addressed in 2010 in order for FPSC staff to assess PEF's study in combination with other utilities anticipated to submit nuclear decommissioning studies in 2010. PEF will not be required to prepare a new site-specific nuclear decommissioning study in 2010; however, PEF will be required to update the 2008 study with the most currently available escalation rates in 2010. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2008 dollars, is $751 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. See Note 7D for information about the NRC operating license held by PEF for CR3. Based on the 2008 estimate and assumed operating license renewal, PEF increased its asset retirement cost and its ARO liability by approximately $19 million in 2008. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended under the terms of previous base rate settlement agreements. PEF expects to continue this suspension based on its planned 2010 nuclear decommissioning filing. In addition, the wholesale accrual on PEF's reserves for nuclear decommissioning was suspended retroactive to January 2006, following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF received an updated fossil dismantlement study estimate in 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing. PEF's reserve for fossil plant dismantlement was approximately $143 million and $145 million at December 31, 2009 and 2008, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended under the terms of previous base rate settlement agreements.

PEC and PEF have recognized ARO liabilities related to asbestos abatement costs. The ARO liabilities related to asbestos abatement costs were $27 million and $21 million at December 31, 2009 and 2008, respectively, at PEC and $27 million and $24 million at December 31, 2009 and 2008, respectively, at PEF.

Additionally, PEC and PEF have recognized ARO liabilities related to landfill capping costs. The ARO liabilities related to landfill capping costs were $1 million at December 31, 2009 and 2008, at PEC and $6 million at December 31, 2009 and 2008, at PEF. For PEC, closure work related to the landfill commenced in 2009 and should be completed in 2010.

We have identified but not recognized AROs related to electric transmission and distribution and telecommunications assets as the result of easements over property not owned by us. These easements are generally perpetual and require retirement action only upon abandonment or cessation of use of the property for the specified purpose. The ARO is not estimable for such easements, as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO would be recorded at that time.

The following table presents the changes to the AROs during the years ended December 31, 2009 and 2008. Revisions to prior estimates of the PEC and PEF regulated ARO are related to the updated cost estimates for nuclear decommissioning and asbestos described above.

(in millions)	Progress Energy	PEC	PEF
Asset retirement obligations at January 1, 2008	$1,378	$1,063	$315
Additions	7	1	6
Accretion expense	79	62	17
Revisions to prior estimates	7	(4)	11
Asset retirement obligations at December 31, 2008	1,471	1,122	349
Accretion expense	**83**	**65**	**18**
Revisions to prior estimates	**(384)**	**(386)**	**2**
Asset retirement obligations at December 31, 2009	**$1,170**	**$801**	**$369**

D. INSURANCE

The Utilities are members of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities. Under the primary program, each company is insured for $500 million at each of its respective nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $1.750 billion on each nuclear plant.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under this program, following a 12-week deductible period, for 52 weeks in the amount of $3.5 million per week at Brunswick, Harris and Robinson, and $4.5 million per week at CR3. An additional 110 weeks of coverage is provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $28 million with respect to the primary coverage, $40 million with respect to the decontamination, decommissioning and excess property coverage, and $25 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate the plant, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $12.595 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from each insured nuclear incident exceed the primary level of coverage provided by American Nuclear Insurers, each company would be subject to pro rata assessments of up to $117.5 million for each reactor owned for each incident. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $17.5 million per reactor owned per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before August 29, 2013.

Under the NEIL policies, if there were multiple terrorism losses within one year, NEIL would make available one industry aggregate limit of $3.240 billion for noncertified acts, along with any amounts it recovers from reinsurance, government indemnity or other sources up to the limits for each claimant. If terrorism losses occurred beyond the one-year period, a new set of limits and resources would apply.

The Utilities self-insure their transmission and distribution lines against loss due to storm damage and other natural disasters. PEF maintains a storm damage reserve pursuant to a regulatory order and may defer losses in excess of the reserve (See Note 7C).

5. RECEIVABLES

Income taxes receivable and interest income receivables are not included in receivables. These amounts are included in prepayments and other current assets or shown separately on the Consolidated Balance Sheets. At December 31 receivables were comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Trade accounts receivable	**$581**	$648	**$291**	$350	**$288**	$298
Unbilled accounts receivable	**193**	182	**125**	120	**68**	62
Notes receivable	–	2	–	–	–	–
Derivatives accounts receivable	**2**	–	–	–	**2**	–
Other receivables	**42**	53	**34**	38	**8**	13
Allowance for doubtful receivables	**(18)**	(18)	**(8)**	(6)	**(10)**	(11)
Total receivables, net	**$800**	$867	**$442**	$502	**$356**	$362

6. INVENTORY

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Fuel for production	**$667**	$614	**$304**	$287	**$363**	$327
Materials and supplies	**639**	588	**366**	338	**273**	250
Emission allowances	**18**	37	**6**	8	**12**	29
Other	**1**	–	**1**	–	–	–
Total inventory	**$1,325**	$1,239	**$677**	$633	**$648**	$606

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits on the Consolidated Balance Sheets for Progress Energy of $24 million and $23 million at December 31, 2009 and 2008, respectively.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits on the Consolidated Balance Sheets for Progress Energy, PEC and PEF of $39 million, $8 million and $31 million, respectively, at December 31, 2009. Long-term emission allowances for Progress Energy, PEC and PEF were $61 million, $14 million and $47 million, respectively, at December 31, 2008.

7. REGULATORY MATTERS

A. REGULATORY ASSETS AND LIABILITIES

As regulated entities, the Utilities are subject to the provisions of GAAP for regulated operations. Accordingly, the Utilities record certain assets and liabilities resulting from the effects of the ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utilities' ability to continue to meet the criteria for application of GAAP for regulated operations could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that GAAP for regulated operations no longer applies to a separable portion of our operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, such an event would require the Utilities to determine if any impairment to other assets, including utility plant, exists and write down impaired assets to their fair values.

Except for portions of deferred fuel costs and loss on reacquired debt, all regulatory assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. We expect to fully recover our regulatory assets and refund our regulatory liabilities through customer rates under current regulatory practice.

At December 31 the balances of regulatory assets (liabilities) were as follows:

Progress Energy

(in millions)	**2009**	2008
Deferred fuel cost – current (Notes 7B and 7C)	**$105**	$335
Nuclear deferral (Note 7C)	**37**	190
Environmental	**–**	8
Total current regulatory assets	**142**	533
Deferred fuel cost – long-term (Note 7B)[(a)]	**62**	130
Nuclear deferral (Note 7C) [(a)]	**239**	–
Deferred impact of ARO (Note 4C)[(b)]	**99**	348
Income taxes recoverable through future rates[(b)]	**264**	193
Loss on reacquired debt[(c)]	**35**	37
Storm deferral (Note 7C)[(d)]	**10**	16
Postretirement benefits (Note 16)[(e)]	**945**	1,042
Derivative mark-to-market adjustment (Note 17A)[(f)]	**436**	697
Environmental (Notes 7C and 21A)[(g)]	**24**	31
Accrued vacation[(a)]	**10**	32
DSM / Energy-efficiency deferral (Note 7B)[(h)]	**19**	9
Other	**36**	32
Total long-term regulatory assets	**2,179**	2,567
Environmental (Note 7C)	**(24)**	–
Deferred energy conservation cost and other current regulatory liabilities	**(3)**	(6)
Total current regulatory liabilities	**(27)**	(6)
Non-ARO cost of removal (Note 4C)[(b)]	**(1,866)**	(1,748)
Deferred impact of ARO (Note 4C)[(b)]	**(150)**	(198)
Net nuclear decommissioning trust unrealized gains (Note 4C)[(i)]	**(295)**	(28)
Derivative mark-to-market adjustment (Note 17A)[(f)]	**(20)**	(26)
Storm reserve (Note 7C)[(g)]	**(136)**	(129)
Other	**(43)**	(52)
Total long-term regulatory liabilities	**(2,510)**	(2,181)
Net regulatory (liabilities) assets	**$(216)**	$913

PEC

(in millions)	**2009**	2008
Deferred fuel cost – current (Note 7B)	**$88**	$207
Deferred fuel cost – long-term (Note 7B)[a]	**62**	130
Deferred impact of ARO (Note 4C)[b]	**92**	343
Income taxes recoverable through future rates[b]	**76**	62
Loss on reacquired debt[c]	**15**	16
Postretirement benefits (Note 16)[e]	**483**	522
Derivative mark-to-market adjustment (Note 17A)[f]	**88**	96
Accrued vacation[a]	**10**	32
DSM / Energy-efficiency deferral[h]	**19**	9
Other	**28**	33
Total long-term regulatory assets	**873**	1,243
Non-ARO cost of removal (Note 4C)[b]	**(1,094)**	(948)
Net nuclear decommissioning trust unrealized gains (Note 4C)[i]	**(181)**	(21)
Other	**(18)**	(18)
Total long-term regulatory liabilities	**(1,293)**	(987)
Net regulatory (liabilities) assets	**$(332)**	$463

PEF

(in millions)	2009	2008
Deferred fuel cost – current (Note 7C)	**$17**	$128
Nuclear deferral (Note 7C)	**37**	190
Environmental	**–**	8
Total current regulatory assets	**54**	326
Nuclear deferral (Note 7C)[a]	**239**	–
Income taxes recoverable through future rates[b]	**188**	131
Loss on reacquired debt[c]	**20**	21
Storm deferral (Note 7C)[d]	**10**	14
Postretirement benefits (Note 16)[e]	**462**	520
Derivative mark-to-market adjustment (Note 17A)[f]	**348**	601
Environmental (Notes 7C and 21A)[g]	**19**	21
Other	**21**	16
Total long-term regulatory assets	**1,307**	1,324
Environmental (Note 7C)	**(24)**	–
Deferred energy conservation cost and other current regulatory liabilities	**(3)**	(6)
Total current regulatory liabilities	**(27)**	(6)
Non-ARO cost of removal (Note 4C)[b]	**(772)**	(800)
Deferred impact of ARO (Note 4C)[b]	**(30)**	(76)
Net nuclear decommissioning trust unrealized gains (Note 4C)[i]	**(114)**	(7)
Derivative mark-to-market adjustment (Note 17A)[f]	**(20)**	(26)
Storm reserve (Note 7C)[g]	**(136)**	(129)
Other	**(31)**	(38)
Total long-term regulatory liabilities	**(1,103)**	(1,076)
Net regulatory assets	**$231**	$568

The recovery and amortization periods for these regulatory assets and (liabilities) at 2009 are as follows:

(a) Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding five years.

(b) Asset retirement and removal liabilities are recorded and income taxes recoverable through future rates are recovered over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and adjusted following completion of the related activities.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 30 years.

(d) Recorded and recovered or amortized as approved by the FERC over a period not exceeding five years.

(e) Recovered and amortized over the remaining service period of employees. In accordance with a 2009 FPSC order, PEF's 2009 deferred pension expense of $34 million will be amortized to the extent that annual pension expense is less than the $27 million allowance provided for in base rates (See Note 7C).

(f) Related to derivative unrealized gains and losses that are recorded as a regulatory liability or asset, respectively, until the contracts are settled. After settlement of the derivatives and the fuel is consumed, the realized gains or losses are passed through the fuel cost-recovery clause.

(g) Recovered as environmental remediation or storm restoration expenses are incurred.

(h) Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding 10 years.

(i) Related to unrealized gains and losses on nuclear decommissioning trust funds that are recorded as a regulatory asset or liability, respectively, until the funds are used to decommission a nuclear plant.

B. PEC RETAIL RATE MATTERS

BASE RATES

PEC's base rates are subject to the regulatory jurisdiction of the NCUC and SCPSC. In PEC's most recent rate cases in 1988, the NCUC and the SCPSC each authorized a return on equity of 12.75 percent. In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from their North Carolina coal-fired power plants in phases by 2013. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended December 31, 2007, unless there were extraordinary events beyond the control of the utilities or unless the utilities persistently earned a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. There were no adjustments to PEC's base rates during the five-year period ended December 31, 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation. During the rate freeze period, the legislation provided for a minimum amortization and recovery of 70 percent of the original estimated compliance costs of $813 million (or $569 million) while providing flexibility in the amount of annual amortization recorded from none up to $174 million per year.

For the years ended December 31, 2008 and 2007, PEC recognized Clean Smokestacks Act amortization of $15 million and $34 million, respectively, and recognized $584 million in cumulative amortization through December 31, 2008. The NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million as the projects are closed to plant in service. As a result of this order, PEC did not amortize $229 million of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, but will record depreciation over the useful lives of the assets.

See Note 21B for additional information about the Clean Smokestacks Act.

FUEL COST RECOVERY

On May 7, 2009, PEC filed with the SCPSC for a decrease in the fuel rate charged to its South Carolina ratepayers. On May 28, 2009, PEC jointly filed a settlement agreement with the South Carolina Office of Regulatory Staff and Nucor Steel. Under the terms of the settlement agreement, the parties agreed to PEC's proposed rate reduction of approximately $13 million. On June 19, 2009, the SCPSC approved the settlement agreement. The decrease was effective July 1, 2009, and decreased residential electric bills by $2.08 per 1,000 kilowatt-hours (kWh), or 2.0 percent, for fuel cost recovery. At December 31, 2009, PEC's South Carolina under-recovered deferred fuel balance was $2 million.

On June 4, 2009, and as updated on August 17, 2009, PEC filed with the NCUC for a $14 million decrease in the fuel rate charged to its North Carolina ratepayers, driven by declining fuel prices. On November 16, 2009, the NCUC approved PEC's request. Effective December 1, 2009, residential electric bills decreased by $0.45 per 1,000 kWh, or 0.4 percent, for fuel cost recovery. At December 31, 2009, PEC's North Carolina under-recovered deferred fuel balance was $148 million, of which $62 million is expected to be collected after 2010 and has been classified as a long-term regulatory asset.

DEMAND-SIDE MANAGEMENT AND ENERGY-EFFICIENCY COST RECOVERY

Comprehensive energy legislation enacted by North Carolina in 2007 allows PEC to recover the costs of demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs intended to produce future benefits and authorizes the NCUC to approve other forms of financial incentives to the utility for DSM and energy-efficiency programs. DSM programs include, but are not limited to, any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control, interruptible load and electric system equipment and operating controls. PEC has implemented a series of DSM and energy-efficiency programs and will continue to pursue additional programs. These programs must be approved by the NCUC, and we cannot predict the outcome of the DSM and energy-efficiency filings currently pending approval by the NCUC or whether the implemented programs will produce the expected operational and economic results. At December 31, 2009, PEC's deferred North Carolina DSM and energy-efficiency costs totaled $15 million.

On June 6, 2008, and as subsequently amended, PEC filed an application with the NCUC for approval of a DSM and energy-efficiency rider to recover all program costs, including the recovery of appropriate incentives for investing in such programs. On November 14, 2008, the NCUC issued an order allowing PEC to implement the rates requested in PEC's November 14, 2008 revision to its initial application. The new rates, subject to true-up to the final order, were implemented on December 1, 2008, increasing residential electrical bills by $0.74 per 1,000 kWh, or 0.8 percent. As a result of settlement agreements entered into in 2007 and resulting regulatory proceedings, the NCUC ordered PEC to recalculate rates and submit to the NCUC for approval. The 2009 impact of these revised rates was immaterial.

On June 4, 2009, and as updated on August 17, 2009, PEC requested the NCUC approve a $1 million increase in the DSM and energy-efficiency rate charged to its North Carolina ratepayers. Due to changes in how the costs are allocated among customer classes, the request results in a decrease to the residential rate, while increasing rates for other customer classes. The rate change was approved on an interim basis effective December 1, 2009, and decreased residential electric bills by $0.19 per 1,000 kWh, or 0.2 percent.

On June 27, 2008, PEC filed an application with the SCPSC to establish procedures that encourage investment in cost-effective energy-efficient technologies and energy conservation programs and approve the establishment of an annual rider to allow recovery for all costs associated with such programs, as well as the recovery of appropriate incentives for investing in such programs. On January 23, 2009, PEC filed a Stipulation Agreement between PEC and some of the other parties to the proceeding. On May 6, 2009, the SCPSC approved the Stipulation Agreement and issued a directive requiring PEC to file for approval of all proposed DSM and energy-efficiency programs. On May 11, 2009, in accordance with the SCPSC directive, PEC filed its programs for approval and an application for a cost-recovery rider for PEC's DSM and energy-efficiency programs. On June 10, 2009, SCPSC approved the proposed DSM and energy-efficiency programs and the cost-recovery rider application, on a provisional basis pending a review of the cost-recovery rider by the South Carolina Office of Regulatory Staff. The rate increase was effective July 1, 2009, and increased residential electric bills by $0.79 per 1,000 kWh, or 0.8 percent, for DSM and energy-efficiency cost recovery. We cannot predict the outcome of this matter. At December 31, 2009, PEC's deferred South Carolina DSM and energy-efficiency costs totaled $4 million.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD COST RECOVERY

Beginning in 2009, PEC is required to file an annual North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) compliance report with the NCUC demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC REPS requirement via renewable energy certificates (REC) earned after January 1, 2008. The NCUC has selected APX, Inc. as the vendor for implementation of a statewide REC tracking system. North Carolina electric power suppliers with a renewable energy compliance obligation, including PEC, will participate in the registry. Rates for the NC REPS clause are set based on projected costs with true-up provisions. On June 4, 2009 and as updated August 17, 2009, PEC filed with the NCUC for a $7 million increase in the NC REPS rate charged to its North Carolina ratepayers. On November 12, 2009, the NCUC approved PEC's request effective December 1, 2009. PEC's residential electric bills increased by $0.29 per month, or 0.3 percent, for renewable energy portfolio standard (REPS) cost recovery.

ENVIRONMENTAL COMPLIANCE COST RECOVERY

On February 11, 2009, the SCPSC issued an order allowing PEC to begin deferring as a regulatory asset the depreciation expense that PEC incurs on its environmental compliance control facilities as well as the incremental operation and maintenance expenses that PEC incurs in connection with its environmental compliance control facilities. At December 31, 2009, PEC's South Carolina environmental compliance cost-recovery balance was $5 million.

OTHER MATTERS

The NCUC and the SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The North Carolina aggregate minimum and maximum amounts of cost recovery were $415 million and $585 million, respectively, with flexibility in the amount of annual depreciation recorded, from none to $150 million per year. Accelerated cost recovery of these assets resulted in additional depreciation expense of $52 million and $37 million for the years ended December 31, 2008 and 2007, respectively. PEC reached the minimum amount of $415 million of cost recovery by December 31, 2008, and no additional depreciation expense from accelerated cost recovery was recorded in 2009. The South Carolina aggregate minimum and maximum amounts of cost recovery were $115 million and $165 million, respectively. Prior to the SCPSC's 2008 approval to terminate PEC's remaining obligation to accelerate the cost recovery of PEC's nuclear generating assets, PEC had recorded cumulative accelerated depreciation of $77 million for the South Carolina jurisdiction. As a result of the SCPSC's 2008 approval, PEC will not be required to recognize the remaining $38 million of accelerated depreciation required to reach the minimum amount of cost recovery for the South Carolina jurisdiction, but will record depreciation over the useful lives of the assets. No additional depreciation expense from accelerated cost recovery for the South Carolina jurisdiction was recorded in 2009, 2008 or 2007.

On April 30, 2008, PEC submitted a revised Open Access Transmission Tariff (OATT) filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula-based rates for the PEC OATT in order to more accurately reflect the costs that PEC incurs in providing transmission service. In the filing, PEC proposed to move from a fixed revenue requirement to a formula-based rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. The settlement was approved by FERC and new rates were implemented on July 1, 2008. On May 15, 2009, PEC filed its annual update to the formula-based OATT rates. The new rates were effective June 1, 2009, and increased 2009 revenues by $4 million.

On October 13, 2008, the NCUC issued a Certificate of Public Convenience and Necessity allowing PEC to proceed with plans to construct an approximately 600-MW combined cycle dual fuel-capable generating facility at its Richmond County generation site to provide additional generating and transmission capacity to meet the growing energy demands of southern and eastern North Carolina. PEC expects that the new generating and transmission capacity will be online by the second quarter of 2011.

North Carolina enacted a law in July 2009 that abbreviates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal units at that specific site. On August 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C. PEC projects that the generating facility would be in service by January 2013. PEC proposed that upon completion of the generating facility, it will permanently cease operation of the three coal-fired generating units, with a combined generating capacity of approximately 400 MW, that are currently in operation at the site. This will result in approximately 550 MW of incremental capacity. On September 21, 2009, the Public Staff recommended that the NCUC issue the certificate subject to additional conditions as follows: the facility be constructed and operated in accordance with all applicable laws and regulations, PEC file with the NCUC a progress report and any revisions in the cost estimates on an annual basis, PEC permanently cease operation of the three coal-fired units immediately upon completion and placement into service of the facility and that the NCUC clarify that the issuance of the certificate does not constitute approval of the final costs associated with construction of the facility. On October 1, 2009, the NCUC issued a notice of decision stating it found good cause to issue an order granting PEC the certificate subject to the four conditions proposed by the Public Staff as well as adding a condition that PEC submit for NCUC approval a plan to retire additional coal-fired capacity reasonably proportionate to the 550 MW of incremental capacity. On October 22, 2009, the NCUC issued its order granting PEC the certificate to construct the 950-MW facility.

On December 1, 2009, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. PEC intends to continue to depreciate these units using the current depreciation rates as on file with the NCUC and the SCPSC until PEC completes and files a new depreciation study.

On December 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C. PEC projects that the generating facility would be in service by late 2013 or early 2014. PEC proposed that upon completion of the generating facility, it will permanently cease operation of the three coal-fired generating units currently in operation at the site that do not have scrubbers. These units have a combined generating capacity of approximately 600 MW.

C. PEF RETAIL RATE MATTERS

BASE RATES

As a result of a base rate proceeding in 2005, PEF was party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and remained in effect through the last billing cycle of December 2009.

On March 20, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF filed with the FPSC a proposal for an increase in base rates effective January 1, 2010. In its filing, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and approve annual rate relief for PEF of $499 million, which included PEF's petition for a combined $76 million of new base rates in 2009 as discussed below. The request for increased base rates was based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems.

Included within the base rate proposal was a request for an interim base rate increase of $13 million. Additionally, on March 20, 2009, PEF petitioned the FPSC for a limited proceeding to include in base rates revenue requirements of $63 million for the repowered Bartow Plant, which began commercial operations in June 2009. On May 19, 2009, the FPSC approved both the annualized interim base rate increase and the cost recovery for the repowered Bartow Plant subject to refund with interest effective July 1, 2009. Based on actual energy sales, the interim and limited base rate relief increased revenues by $79 million during the year ended December 31, 2009. The changes increased residential bills by approximately $4.52 per 1,000 kWh, or 3.7 percent. On July 2, 2009, Florida's Office of Public Counsel (OPC), the Florida Industrial Power Users Group, the attorney general, the Florida Retail Federation and PCS Phosphate filed a petition protesting portions of the FPSC approval. On August 31, 2009, the FPSC issued an order to consolidate the interim and limited base rate relief increase and the base rate proposal. PEF's remaining base rate request as filed by PEF would have increased residential bills by approximately $9.66 per 1,000 kWh, or 7.6 percent, effective January 1, 2010. A hearing was held on this matter September 21, 2009 – October 1, 2009. On October 27, 2009, the FPSC held a hearing to determine if the voting of pending rate cases should be delayed until new FPSC appointees took office in January 2010. During the hearing, the FPSC voted to delay the rulings on the appropriate level of revenue requirements until January 11, 2010.

On January 11, 2010, the FPSC approved a base rate increase of $132 million effective January 1, 2010, which represents the annualized impact of the rate increase that was approved and effective July 2009 for the repowered Bartow Plant. Additionally, the FPSC did not require PEF to refund the 2009 interim base rate increase previously discussed. The difference between PEF's requested $499 million incremental revenues and the $132 million granted by the FPSC is a function of several factors, including, among other things: 1) PEF had proposed rates based on a return on equity of 12.54 percent and the FPSC granted rates based on a return on equity of 10.5 percent; 2) the FPSC granted rates based on projected annual depreciation expense that is approximately $119 million lower than the amount requested by PEF; and 3) the FPSC's ruling incorporates projected annual operating and maintenance (O&M) costs that are approximately $77 million lower than the O&M cost requested by PEF and the elimination of $15 million of annual storm reserve accrual, which represented a $9 million increase over the accrual previously in effect. We are currently reviewing our regulatory options in Florida.

FUEL COST RECOVERY

On March 17, 2009, PEF received approval from the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $206 million reduction in fuel charges to retail customers as a result of effective fuel purchasing strategies and lower fuel prices. The approval reduced residential customers' fuel charges by $6.90 per 1,000 kWh, or 5.0 percent, starting with the first billing cycle of April 2009, with similar reductions for commercial and industrial customers.

On August 10, 2006, Florida's OPC filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers alleged excessive past fuel-recovery charges and SO_2 allowance costs during the period 1996 to 2005. During the period specified in the petition, PEF's costs recovered through fuel-recovery clauses were annually reviewed for prudence and approval by the FPSC. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the FPSC found that PEF had not been prudent in purchasing a portion of its coal requirements during the period from 2003 to 2005. Accordingly, the FPSC ordered PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. For the year ended December 31, 2007, PEF recorded a pre-tax other operating expense of $12 million, interest expense of $2 million and an associated $14 million regulatory liability. The refund was returned to ratepayers in 2008 through a reduction of prior year under-recovered fuel costs. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for Crystal River Units No. 4 and 5 coal-fired steam turbines (CR4 and CR5). On February 2, 2009, the OPC filed direct testimony alleging that during 2006 and 2007, PEF collected excessive fuel costs and SO_2 allowance costs of $61 million before interest. The OPC claimed that these excessive costs were attributed to PEF's ongoing practice of not blending the most economical sources of coal at its CR4 and CR5 Plants. During the hearing on the matter, the OPC reduced the alleged excessive fuel costs to $33 million before interest. On June 30, 2009, the FPSC approved a refund of $8 million to PEF's ratepayers to be paid over a 12-month period beginning January 1, 2010, and ordered PEF to file a report by September 2009 regarding the prospective application of PEF's coal procurement plan and the prudence of PEF's coal procurement actions. In compliance with the FPSC order, PEF filed the coal procurement status report on September 14, 2009. For the year ended December 31, 2009, PEF recorded a pre-tax other operating expense of $8 million, an immaterial amount of interest and an associated regulatory liability included within PEF's deferred fuel cost at December 31, 2009. PEF chose not to appeal the FPSC's order.

On September 14, 2009, PEF filed a request with the FPSC to seek approval of a cost adjustment to reduce fuel costs by $105 million, thereby decreasing residential electric bills by $3.34 per 1,000 kWh, or 2.6 percent, effective January 1, 2010. This decrease is due to a decrease of $9.89 per 1,000 kWh for the projected recovery of fuel costs, partially offset by an increase of $6.55 per 1,000 kWh for the projected recovery through the capacity cost-recovery clause (CCRC). The decrease in projected fuel costs is due primarily to a decrease in the price of natural gas and a change in the expected average fuel costs. An extended biennial nuclear outage at CR3 for an uprate project in 2009 contributed to higher projected fuel costs for 2009; however, anticipated changes in the generation mix for 2010 are expected to result in lower average fuel costs and contributed to the projected decrease in 2010 fuel costs. The increase in the CCRC is primarily the result of projected costs to be incurred in 2010 under the nuclear cost-recovery rule discussed below for the proposed nuclear plant in Levy County, Fla. (Levy) and an under-recovery of purchased power costs in 2009. On October 23, 2009, as a result of the October 16, 2009 FPSC vote in the nuclear cost-recovery matter discussed more fully below, PEF filed a $3 million cost adjustment with the FPSC, which reduced the CCRC rate by $0.08 per 1,000 kWh from the original September 14, 2009 cost-adjustment filing. The FPSC approved PEF's fuel and capacity clause filings on November 2, 2009, to be effective January 1, 2010.

On August 28, 2009, PEF filed a request to increase the Environmental Cost Recovery Clause (ECRC) residential rate and the filing was updated on October 27, 2009. PEF is asking the FPSC to increase residential rates by $2.25 per 1,000 kWh, or 1.8 percent. This would increase projected revenues by $33 million. This increase is primarily due to the return on assets expected to be placed in service at the end of 2009. On September 14, 2009, PEF filed a request to increase the Energy Conservation Cost Recovery Clause (ECCR) residential rate by $0.47 per 1,000 kWh, or 0.4 percent. This would increase projected revenues by $4 million. This increase is due mainly to an increase in conservation program costs. The FPSC approved PEF's ECRC and ECCR clause filings on November 2, 2009, to be effective January 1, 2010.

NUCLEAR COST RECOVERY

Levy Nuclear

On March 11, 2008, PEF filed a petition for an affirmative Determination of Need for its proposed Levy Units 1 and 2 nuclear power plants, together with the associated facilities, including transmission lines and substation facilities. Levy Units 1 and 2 are needed to maintain electric system reliability and integrity, fuel and generating diversity and to continue to provide adequate electricity to PEF's customers at a reasonable cost. Levy Units 1 and 2 will be advanced passive light water nuclear reactors, each with a generating capacity of approximately 1,100 MW. The petition included projections that Levy Unit 1 would be placed in service by June 2016 and Levy Unit 2 by June 2017. The filed, nonbinding project cost estimate for Levy Units 1 and 2 was approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities. The FPSC issued the final order granting the petition for the Determination of Need for the proposed nuclear units on August 12, 2008.

On March 11, 2008, PEF also filed a petition with the FPSC to open a discovery docket regarding the actual and projected costs of Levy. PEF filed the petition to assist the FPSC in the timely and adequate review of the proposed project's costs recoverable under the nuclear cost-recovery rule. On May 1, 2008, PEF filed a petition for recovery of both preconstruction and carrying charges on construction costs incurred or anticipated to be incurred during 2008 and 2009 under the nuclear cost-recovery rule. Based on the affirmative vote by the FPSC on the Determination of Need for Levy, PEF filed a petition on July 18, 2008, to recover all prudently incurred costs under the nuclear cost-recovery rule. On November 12, 2008, the FPSC issued an order to approve the inclusion of preconstruction and carrying charges of $357 million as well as site selection costs of $38 million in establishing PEF's 2009 capacity cost-recovery clause factor.

On March 17, 2009, PEF received approval from the FPSC to defer until 2010 the recovery of $198 million of nuclear preconstruction costs for Levy, which the FPSC had authorized to be collected in 2009. The approval reduced residential customers' nuclear cost-recovery charge by $7.80 per 1,000 kWh, or 5.7 percent, starting with the first billing cycle of April 2009, with similar reductions for commercial and industrial customers.

On May 1, 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consists of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. This alternate proposal reduced the 2010 revenue requirement to $236 million. On September 14, 2009, consistent with FPSC rules, PEF included both proposed revenue requirements in its CCRC filing, which would result in a nuclear cost-recovery charge of either $7.98 per 1,000 kWh for residential customers under PEF's alternate proposal, or $15.07 per 1,000 kWh if the FPSC did not approve PEF's alternate proposal. At a special agenda hearing by the FPSC on October 16, 2009, the FPSC approved the alternate proposal allowing PEF to recover $207 million of revenue requirements associated with the nuclear cost-recovery clause through the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. This revenue level results in a nuclear cost-recovery charge of $6.99 per 1,000 kWh, which represents a $2.68 increase per 1,000 kWh for residential customer bills. In adopting PEF's proposed rate management plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts.

On October 16, 2009, the FPSC clarified certain implementation policies related to the recognition of deferrals and the application of carrying charges under the nuclear cost-recovery rule. Specifically, the FPSC clarified that (1) nuclear costs are deemed to be recovered up to the amount of FPSC-approved projections and (2) the deferral of unrecovered nuclear costs would accrue a carrying charge at PEF's approved AFUDC rate consistent with the requirements of FPSC's nuclear cost-recovery rule, which is fixed at the pre-tax AFUDC rate in effect as of June 12, 2007. Accordingly, PEF retrospectively assigned capacity revenues to match the FPSC-approved projected level of nuclear cost recovery as of September 30, 2009. Nuclear costs incurred in excess of original projections earn a carrying charge equal to the AFUDC rate. Prior to the FPSC clarification, PEF assigned capacity revenues to nuclear cost recovery based on actual costs incurred; any over- or under-recoveries of actual costs were deferred and earned a carrying charge equal to a commercial paper rate.

On November 19, 2009, the FPSC issued a final order approving the recovery of prudently incurred nuclear costs as a part of PEF's proposed rate management plan. The rate management plan includes the reclassification to the nuclear cost-recovery clause regulatory asset of the 1) $198 million of capacity revenues and 2) the accelerated amortization of $76 million of preconstruction costs. The cumulative amount of $274 million was recorded as a nuclear cost-recovery regulatory asset at December 31, 2009, and is projected to be recovered by 2014.

The FPSC has authorized alternative cost-recovery mechanisms for preconstruction and construction carrying costs of nuclear power plants. Accordingly, at December 31, 2009 and 2008, PEF reflected $276 million and $190 million, respectively, of nuclear-related costs as a regulatory asset, of which $274 million and $174 million, respectively, represents construction work in progress (See Note 4A). Of the total $276 million of nuclear-related costs at December 31, 2009, $275 million related to Levy. The total $190 million of nuclear-related costs at December 31, 2008, was comprised of $181 million related to Levy and $9 million related to the CR3 uprate.

CR3 Uprate

On August 28, 2009, PEF filed a petition with the FPSC to approve a $17 million base rate increase for the phase II costs associated with the uprate of CR3. PEF's 2009 revenue requirements for recovery of the phase II costs were included in the CCRC. As permitted under the nuclear cost-recovery rule, PEF's phase III costs associated with the CR3 uprate are currently being recovered through the CCRC discussed above. On October 29, 2009, the FPSC Staff recommended that the FPSC approve PEF's request with minor modifications and that the new rates be implemented at the same time as PEF implements new base rates from its rate case proceeding. On October 30, 2009, PEF filed an amended petition requesting this rate change be implemented effective January 1, 2010. On December 1, 2009, the FPSC approved an increase in base rates for residential customers by $0.57 per 1,000 kWh, or 0.4 percent.

STORM COST RECOVERY

In 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power associated with four hurricanes in 2004. The net impact was included in customer bills beginning January 1, 2006. In 2007, PEF recorded the remaining amortization of $75 million associated with the recovery of these storm costs.

During 2006, the FPSC approved a settlement agreement between PEF and certain intervenors in its storm cost-recovery docket that would allow PEF to extend its then-current two-year storm surcharge, which equals approximately $3.61 on the average residential monthly customer bill of 1,000 kWh, for an additional 12-month period that began August 2007 to replenish its storm reserve. Additionally, the settlement agreement provided that in the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence. In 2008, PEF recorded net additional storm reserve of $66 million from the extension of the storm surcharge. The surcharge agreement expired in August 2008. At December 31, 2009 and 2008, PEF's storm reserve totaled $136 million and $129 million, respectively.

OTHER MATTERS

On October 29, 2007, PEF submitted a revised OATT filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula-based rates for the PEF OATT in order to more accurately reflect the costs that PEF incurs in providing transmission service. In the filing, PEF proposed to move from a fixed rate to a formula-based rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. The settlement was approved by FERC and new rates were implemented on January 1, 2008. On May 15, 2009, PEF filed its annual update to the formula-based OATT rates. The new rates were effective June 1, 2009, and increased 2009 revenues by $2 million. In addition, one of PEF's large wholesale customers became subject to the new rate structure on September 1, 2009, increasing PEF's 2009 revenues by an additional $4 million.

On March 20, 2009, PEF filed a petition with the FPSC for expedited approval of the deferral of $53 million in 2009 pension expense and the authorization to charge $33 million in estimated 2009 storm hardening expenses to its storm damage reserve. PEF requested that the deferral of pension expense continue until the recovery of these costs is provided for in FPSC-approved base rates. On June 16, 2009, the FPSC denied PEF's request related to the storm hardening expenses, but approved the deferral of the retail portion of actual 2009 pension expense. As a result of the order, PEF deferred pension expense of $34 million for the year ended December 31, 2009. PEF will not earn a carrying charge on the deferred pension regulatory asset. The deferral of pension expense will not result in a change in PEF's 2009 retail rates or prices. In accordance with the order, subsequent to 2009 PEF will amortize the deferred pension regulatory asset to the extent that annual pension expense is less than the $27 million allowance provided for in the base rates established in the 2010 base rate proceeding. In the event such amortization is insufficient to fully amortize the regulatory asset, PEF can seek recovery of the remaining unamortized amount in a base rate proceeding no earlier than 2015.

D. NUCLEAR LICENSE RENEWALS

PEC's nuclear units are currently operating under licenses that expire between 2010 and 2026. The NRC has granted PEC 20-year renewals of the licenses for its nuclear units, which extend the operating licenses to expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On December 18, 2008, PEF filed an application for a 20-year renewal from the NRC on the operating license for CR3, which would extend the operating license through 2036, if approved. PEF anticipates a decision from the NRC in 2011.

8. GOODWILL

Goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments and our goodwill impairment tests are performed at the utility segment level. At December 31, 2009 and 2008, our carrying amount of goodwill was $3.655 billion, with $1.922 billion assigned to PEC and $1.733 billion assigned to PEF. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment. We perform our annual impairment test as of April 1 of each year. During the second quarter in 2009, we completed the 2009 annual tests, which indicated the goodwill was not impaired.

9. EQUITY

A. COMMON STOCK

PROGRESS ENERGY

At December 31, 2009 and 2008, we had 500 million shares of common stock authorized under our charter, of which 281 million shares and 264 million shares, respectively, were outstanding. For the years ended December 31, 2009, 2008 and 2007, we issued shares of common stock, primarily under a public offering and to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Progress Energy Investor Plus Plan (IPP). In addition, we periodically issue shares for our other benefit plans.

The following table presents information for our common stock issuances:

	Years Ended December 31,					
	2009		2008		2007	
(in millions)	**Shares**	**Net Proceeds**	Shares	Net Proceeds	Shares	Net Proceeds
Total issuances	**17.5**	**$623**	3.7	$132	3.7	$151
Issuances under a public offering	**14.4**	**523**	–	–	–	–
Issuances to meet requirements of 401(k) and IPP	**2.5**	**100**	3.1	131	1.0	46

The shares issued under a public offering were issued on January 12, 2009, at a public offering price of $37.50. We used $100 million of the proceeds to reduce the Parent's revolving credit agreement (RCA) borrowings and the remainder was used for general corporate purposes.

Subsequent to December 31, 2009, the Parent issued approximately 3.6 million shares of common stock resulting in approximately $136 million in proceeds through the IPP. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2009, there were no significant restrictions on the use of retained earnings (See Note 11B).

PEC

At December 31, 2009 and 2008, PEC was authorized to issue up to 200 million shares of common stock. All shares issued and outstanding are held by Progress Energy. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2009, there were no significant restrictions on the use of retained earnings. See Note 11B for additional dividend restrictions related to PEC.

PEF

At December 31, 2009 and 2008, PEF was authorized to issue up to 60 million shares of common stock. All PEF common shares issued and outstanding are indirectly held by Progress Energy. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2009, there were no significant restrictions on the use of retained earnings. See Note 11B for additional dividend restrictions related to PEF.

B. STOCK-BASED COMPENSATION

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. At December 31, 2009 and 2008, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has a matching feature, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes.

There were 0.5 million and 1.1 million ESOP suspense shares at December 31, 2009 and 2008, respectively, with a fair value of $22 million and $45 million, respectively. ESOP shares allocated to plan participants totaled 13.0 million and 12.6 million at December 31, 2009 and 2008, respectively. Our matching compensation cost under the 401(k) is determined based on matching percentages as defined in the plan. Such compensation cost is allocated to participants' accounts in the form of Progress Energy common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. We currently meet common stock share needs with open market purchases, with shares released from the ESOP suspense account and with newly issued shares. Costs for the matching component are typically met with shares in the same year incurred. Matching costs, which were met and will be met with shares released from the suspense account, totaled approximately $13 million, $8 million and $23 million for the years ended December 31, 2009, 2008 and 2007, respectively. We have a long-term note receivable from the 401(k)

Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

We also sponsor the Savings Plan for Employees of Florida Progress Corporation which covers bargaining unit employees of PEF.

Total matching cost for both plans was approximately $41 million, $38 million and $34 million for the years ended December 31, 2009, 2008 and 2007, respectively.

PEC

PEC's matching costs, which were met and will be met with shares released from the suspense account, totaled approximately $8 million, $5 million and $14 million for the years ended December 31, 2009, 2008 and 2007, respectively. Total matching cost was approximately $22 million, $21 million and $18 million for the years ended December 31, 2009, 2008 and 2007, respectively.

PEF

PEF's matching costs, which were met and will be met with shares released from the suspense account, totaled approximately $3 million, $1 million and $4 million for the years ended December 31, 2009, 2008 and 2007, respectively. Total matching cost for both plans was approximately $12 million, $11 million and $10 million for the years ended December 31, 2009, 2008 and 2007, respectively.

STOCK OPTIONS

Pursuant to our 1997 Equity Incentive Plan (EIP) and 2002 EIP, amended and restated as of July 10, 2002, we may grant options to purchase shares of Progress Energy common stock to directors, officers and eligible employees for up to 5 million and 15 million shares, respectively. Generally, options granted to officers and employees vest one-third per year with 100 percent vesting at the end of year three, while options granted to directors vest 100 percent at the end of one year. The options expire 10 years from the date of grant. All option grants have an exercise price equal to the fair market value of our common stock on the grant date. We curtailed our stock option program in 2004 and replaced that compensation program with other programs. No stock options have been granted since 2004. We issue new shares of common stock to satisfy the exercise of previously issued stock options.

PROGRESS ENERGY

A summary of the status of our stock options at December 31, 2009, and changes during the year then ended, is presented below:

(option quantities in millions)	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	1.6	$43.99
Canceled	(0.1)	43.76
Exercised	–	–
Options outstanding, December 31	1.5	44.00
Options exercisable, December 31	1.5	44.00

The options outstanding and exercisable at December 31, 2009, had a weighted-average remaining contractual life of 3.03 years. Aggregate intrinsic value as of December 31, 2009, was not significant. The total intrinsic value of options exercised during the years ended December 31, 2009 and 2008, was not significant. Total intrinsic value of options exercised during the year ended December 31, 2007, was $17 million.

Compensation cost for expense purposes is measured at the grant date based on the fair value of the award and is recognized over the vesting period. All options are fully vested; therefore, no compensation expense was recognized in 2009, 2008 or 2007.

Cash received from the exercise of stock options totaled $105 million during the year ended December 31, 2007. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2007, was $6 million. Cash received from the exercise of stock options for the years ended December 31, 2009 and 2008, was not significant.

PEC

All options are fully vested; therefore, no compensation expense was recognized in 2009, 2008 or 2007.

PEF

All options are fully vested; therefore, no compensation expense was recognized in 2009, 2008 or 2007.

OTHER STOCK-BASED COMPENSATION PLANS

We have additional compensation plans for our officers and key employees that are stock-based in whole or in part. Our long-term compensation program currently includes two types of equity-based incentives: performance shares under the Performance Share Sub Plan (PSSP) and restricted stock programs. The compensation program was established pursuant to our 1997 EIP and was continued under our 2002 and 2007 EIPs, as amended and restated from time to time.

We granted cash-settled PSSP awards prior to 2005. Since 2005, we have been granting stock-settled PSSP awards. Under the terms of the PSSP, our officers and key employees are granted a target number of performance shares on an annual basis that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of Progress Energy common stock, and dividend equivalents are accrued on, and reinvested in, additional performance shares. Prior to 2007, shares issued under the PSSP (both cash-settled and stock-settled) had two equally weighted performance measures, both based on our results as compared to a peer group of utilities. In 2007, the PSSP was redesigned, and shares issued under the revised plan use one performance measure. In 2009, the PSSP was redesigned again, and shares issued under the revised plan use total shareholder return and earnings growth as two equally weighted performance measures. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. For cash-settled awards, compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated to reflect factors such as changes in stock price and the status of performance measures. The stock-settled PSSP is similar to the cash-settled PSSP, except that we distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. We issue new shares of common stock to satisfy the requirements of the PSSP program. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with subsequent adjustments made to reflect the status of the performance measure. Compensation expense for all awards is reduced by estimated forfeitures. PSSP cash-settled liabilities paid in the years ended December 31, 2009, 2008 and 2007, were not significant.

A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2009, and changes during the year then ended is presented below:

	Number of Stock-Settled Performance Shares(a)	Weighted-Average Grant Date Fair Value
Beginning balance	1,118,604	$46.46
Granted	328,369	33.80
Vested	(419,366)	44.23
Paid(b)	(232,793)	50.55
Forfeited	(16,484)	44.27
Ending balance	778,330	45.49

(a) Amounts reflect target shares to be issued. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.
(b) Shares paid include only target shares as originally granted.

For the years ended December 31, 2008 and 2007, the weighted-average grant date fair value of stock-settled performance shares granted was $42.41 and $50.70, respectively.

The Restricted Stock Award program allows us to grant shares of restricted common stock to our officers and key employees. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. Restricted shares are included as shares outstanding in the basic earnings per share calculation.

A summary of the status of the nonvested restricted stock shares at December 31, 2009, and changes during the year then ended, follows:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	192,101	$43.93
Granted	–	–
Vested	(50,297)	44.06
Forfeited	(6,500)	42.79
Ending balance	135,304	43.94

For the year ended December 31, 2007, the weighted-average grant date fair value of restricted stock granted was $49.54. There were no restricted stock shares granted in 2008.

The total fair value of restricted stock awards vested during the years ended December 31, 2009, 2008 and 2007, was $2 million, $3 million and $13 million, respectively. No cash was expended to purchase shares for 2009, and cash expended to purchase shares during 2008 and 2007 was not significant due to the curtailment of the Restricted Stock Award program upon the rollout of the restricted stock unit (RSU) program in 2007.

Beginning in 2007, we began issuing RSUs rather than restricted stock awards for our officers, vice presidents, managers and key employees. RSUs awarded to eligible employees are generally subject to either three- or five-year cliff vesting or five-year graded vesting. We issue new shares of common stock to satisfy the requirements of the RSU program. Compensation expense, based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. RSUs are included as shares outstanding in the basic earnings per share calculation. Units are converted to shares upon vesting.

A summary of the status of nonvested RSUs at December 31, 2009, and changes during the year then ended, follows:

	Number of Restricted Units	Weighted-Average Grant Date Fair Value
Beginning balance	1,076,536	$46.86
Granted	644,231	33.91
Vested	(342,723)	47.18
Forfeited	(39,759)	41.54
Ending balance	1,338,285	43.46

The total fair value of RSUs vested during the year ended December 31, 2009, was $16 million. No cash was expended to purchase stock to satisfy RSU plan obligations in 2009, 2008 and 2007.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $39 million for the year ended December 31, 2009, with a recognized tax benefit of $15 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $31 million with a recognized tax benefit of $12 million and $64 million, with a recognized tax benefit of $24 million, for the years ended December 31, 2008 and 2007, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2009, there was $31 million of total unrecognized compensation cost related to nonvested other stock-based compensation plan awards, which is expected to be recognized over a weighted-average period of 1.56 years.

PEC

PEC's Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $24 million for the year ended December 31, 2009, with a recognized tax benefit of $9 million. The total expense recognized on PEC's Consolidated Statements of Income for other stock-based compensation plans was $18 million with a recognized tax benefit of $7 million and $38 million, with a recognized tax benefit of $15 million, for the years ended December 31, 2008 and 2007, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

PEF

PEF's Statements of Income included total recognized expense for other stock-based compensation plans of $15 million for the year ended December 31, 2009, with a recognized tax benefit of $6 million. The total expense recognized on PEF's Statements of Income for other stock-based compensation plans was $13 million with a recognized tax benefit of $5 million and $21 million, with a recognized tax benefit of $8 million, for the years ended December 31, 2008 and 2007, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

C. EARNINGS PER COMMON SHARE

Basic earnings per common share are based on the weighted-average number of common shares outstanding, which includes the effects of unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents. Diluted earnings per share include the effects of the nonvested portion of performance share awards and the effect of stock options outstanding.

A reconciliation of the weighted-average number of common shares outstanding for the years ended December 31 for basic and dilutive purposes follows:

(in millions)	**2009**	2008	2007
Weighted-average common shares – basic	**279.4**	261.6	257.3
Net effect of dilutive stock-based compensation plans	**0.1**	0.1	0.2
Weighted-average shares – fully diluted	**279.5**	261.7	257.5

There were no adjustments to net income or to income from continuing operations attributable to controlling interests between the calculations of basic and fully diluted earnings per common share. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. The weighted-average ESOP shares totaled 0.7 million, 1.2 million and 1.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. There were 1.5 million, 1.6 million and 0.1 million stock options outstanding at December 31, 2009, 2008 and 2007, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive.

D. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

Components of accumulated other comprehensive (loss) income, net of tax, at December 31 were as follows:

	Progress Energy		PEC		PEF	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
(Loss) gain on cash flow hedges	**$(35)**	$(57)	**$(27)**	$(35)	**$3**	$(1)
Pension and other postretirement benefits	**(52)**	(58)	–	–	–	–
Other	–	(1)	–	–	–	–
Total accumulated other comprehensive (loss) income	**$(87)**	$(116)	**$(27)**	$(35)	**$3**	$(1)

10. PREFERRED STOCK OF SUBSIDIARIES

All of our preferred stock was issued by the Utilities. The preferred stock is considered temporary equity due to certain provisions that could require us to redeem the preferred stock for cash. In the event dividends payable on PEC or PEF preferred stock are in default an amount equivalent to or exceeding four quarterly dividend payments, the holders of the preferred stock are entitled to elect a majority of PEC or PEF's respective board of directors until all accrued and unpaid dividends are paid. All classes of preferred stock are entitled to cumulative dividends with preference to the common stock dividends, are redeemable by vote of the Utilities' respective board of directors at any time, and do not have any preemptive rights. All classes of preferred stock have a liquidation preference equal to $100 per share plus any accumulated unpaid dividends except for PEF's 4.75%, $100 par value class, which does not have a liquidation preference. Each holder of PEC's preferred stock is entitled to one vote. The holders of PEF's preferred stock have no right to vote except for certain circumstances involving dividends payable on preferred stock that are in default or certain matters affecting the rights and preferences of the preferred stock.

At December 31, 2009 and 2008, preferred stock outstanding consisted of the following:

(dollars in millions, except share and per share data)	Shares Authorized	Shares Outstanding	Redemption Price	Total
PEC				
Cumulative, no par value $5 Preferred Stock	300,000			
$5 Preferred		236,997	$110.00	$24
Cumulative, no par value Serial Preferred Stock	20,000,000			
$4.20 Serial Preferred		100,000	102.00	10
$5.44 Serial Preferred		249,850	101.00	25
Cumulative, no par value Preferred Stock A	5,000,000	–	–	–
No par value Preference Stock	10,000,000	–	–	–
Total PEC				59
PEF				
Cumulative, $100 par value Preferred Stock	4,000,000			
4.00% $100 par value Preferred		39,980	104.25	4
4.40% $100 par value Preferred		75,000	102.00	8
4.58% $100 par value Preferred		99,990	101.00	10
4.60% $100 par value Preferred		39,997	103.25	4
4.75% $100 par value Preferred		80,000	102.00	8
Cumulative, no par value Preferred Stock	5,000,000	–	–	–
$100 par value Preference Stock	1,000,000	–	–	–
Total PEF				34
Total preferred stock of subsidiaries				$93

11. DEBT AND CREDIT FACILITIES

A. DEBT AND CREDIT FACILITIES

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2009):

(in millions)		2009	2008
Parent			
Senior unsecured notes, maturing 2010-2039	6.50%	**$4,300**	$2,600
Draws on revolving credit agreement, expiring 2012		**-**	100
Unamortized premium and discount, net		**(7)**	(4)
Current portion of long-term debt		**(100)**	-
Long-term debt, net		**4,193**	2,696
PEC			
First mortgage bonds, maturing 2010-2038	5.60%	**2,525**	2,325
Pollution control obligations, maturing 2017-2024	0.80%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Miscellaneous notes	6.01%	**21**	22
Unamortized premium and discount, net		**(6)**	(7)
Current portion of long-term debt		**(6)**	-
Long-term debt, net		**3,703**	3,509
PEF			
First mortgage bonds, maturing 2010-2038	5.81%	**3,800**	3,800
Pollution control obligations, maturing 2018-2027	0.47%	**241**	241
Medium-term notes, maturing 2028	6.75%	**150**	150
Unamortized premium and discount, net		**(8)**	(9)
Current portion of long-term debt		**(300)**	-
Long-term debt, net		**3,883**	4,182
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(37)**	(37)
Long-term debt, net		**272**	272
Progress Energy consolidated long-term debt, net		**$12,051**	$10,659

On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with proceeds from the $950 million of Senior Notes issued in November 2009.

On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were $523 million. We used $100 million of the proceeds to reduce the Parent's RCA borrowings and the remainder was used for general corporate purposes.

On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds was used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding short-term debt and for general corporate purposes.

On March 19, 2009, the Parent issued an aggregate $750 million of Senior Notes consisting of $300 million of 6.05% Senior Notes due 2014 and $450 million of 7.05% Senior Notes due 2019. A portion of the proceeds was used to fund PEF's capital expenditures through an equity contribution with the remaining proceeds used for general corporate purposes.

On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.

On November 19, 2009, the Parent issued an aggregate $950 million of Senior Notes consisting of $350 million of 4.875% Senior Notes due 2019 and $600 million of 6.00% Senior Notes due 2039. The proceeds were used to retire at maturity the $100 million outstanding Series A Floating Rate Notes due January 15, 2010, to repay outstanding commercial paper balances, to prefund a portion of the $700 million aggregate principal amount due upon maturity of our 7.10% Senior Notes due March 1, 2011, and for general corporate purposes.

At December 31, 2009 and 2008, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2009, we had no outstanding borrowings under our credit facilities. At December 31, 2008, we had $600 million of outstanding borrowings under our credit facilities as shown in the following table, of which $100 million was classified as long-term debt. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following tables summarize our RCAs and available capacity at December 31:

2009 **(in millions)**	**Description**	**Total**	**Outstanding(a)**	**Reserved(b)**	**Available**
Parent	**Five-year (expiring 5/3/12)**	**$1,130**	**$–**	**$177**	**$953**
PEC	**Five-year (expiring 6/28/11)**	**450**	**–**	**–**	**450**
PEF	**Five-year (expiring 3/28/11)**	**450**	**–**	**–**	**450**
Total credit facilities		**$2,030**	**$ –**	**$177**	**$1,853**

2008 (in millions)	Description	Total	Outstanding(a)	Reserved(b)	Available
Parent	Five-year (expiring 5/3/12)	$1,130	$ 600	$99	$431
PEC	Five-year (expiring 6/28/11)	450	–	110	340
PEF	Five-year (expiring 3/28/11)	450	–	371	79
Total credit facilities		$2,030	$ 600	$580	$850

(a) The RCA borrowings outstanding at December 31, 2008, were repaid during 2009.

(b) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009 and 2008, the Parent had $37 million and $30 million, respectively, of letters of credit issued, which were supported by the RCA. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper balance with proceeds from the $950 million November 2009 issuance of Senior Notes.

The RCAs provide liquidity support for issuances of commercial paper and other short-term obligations. Fees and interest rates under Progress Energy's RCA are based upon the credit rating of Progress Energy's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2/Watch Negative by Moody's Investors Service, Inc. (Moody's) and BBB/Watch Negative by Standard & Poor's Rating Service (S&P). Fees and interest rates under PEC's RCA are based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB+/Watch Negative by S&P. Fees and interest rates under PEF's RCA are based upon the credit rating of PEF's long-term unsecured senior noncredit-enhanced debt, currently rated as

A3/Watch Negative by Moody's and BBB+/Watch Negative by S&P.

The following table summarizes short-term debt comprised of the short-term portion of outstanding RCA borrowings and our outstanding commercial paper, and related weighted-average interest rates at December 31:

(in millions)	**2009**		2008	
Parent	**0.49%**	**$140**	2.81%	$569
PEC	–	–	4.36%	110
PEF	–	–	4.41%	371
Total	**0.49%**	**$140**	3.54%	$1,050

The following table presents the aggregate maturities of long-term debt at December 31, 2009:

(in millions)	Progress Energy Consolidated	PEC	PEF
2010	$406	$6	$300
2011	1,000	–	300
2012	950	500	–
2013	825	400	425
2014	300	–	–
Thereafter	9,034	2,809	3,166
Total	$12,515	$3,715	$4,191

B. COVENANTS AND DEFAULT PROVISIONS

FINANCIAL COVENANTS

The Parent's, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2009, the maximum and calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[a]
Parent	68%	58%
PEC	65%	44%
PEF	65%	51%

(a) Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees not recorded on the Consolidated Balance Sheets.

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of the following thresholds: $50 million for the Parent and $35 million each for PEC and PEF. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of their respective cross-default threshold, the lenders of that credit facility could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. The Parent's cross-default provision can be triggered by the Parent and its significant subsidiaries, as defined in the credit agreement. PEC's and PEF's cross-default provisions can be triggered only by defaults of indebtedness by PEC and its subsidiaries and PEF, respectively, not each other or other affiliates of PEC and PEF.

Additionally, certain of the Parent's long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of the Parent, primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $4.3 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither the Parent's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. At December 31, 2009, the Parent had no shares of preferred stock outstanding.

Certain documents restrict the payment of dividends by the Parent's subsidiaries as outlined below.

PEC

PEC's mortgage indenture provides that, as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million, less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2009, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2009, PEC's common stock equity was approximately 55.3 percent of total capitalization. At December 31, 2009, none of PEC's cash dividends or distributions on common stock was restricted.

PEF

PEF's mortgage indenture provides that as long as any first mortgage bonds are outstanding, it will not pay any cash dividends upon its common stock, or make any other distribution to the stockholders, except a payment or distribution out of net income of PEF subsequent to December 31, 1943. At December 31, 2009, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2009, PEF's common stock equity was approximately 53.4 percent of total capitalization. At December 31, 2009, none of PEF's cash dividends or distributions on common stock was restricted.

C. COLLATERALIZED OBLIGATIONS

PEC's and PEF's first mortgage bonds are collateralized by their respective mortgage indentures. Each mortgage constitutes a first lien on substantially all of the fixed properties of the respective company, subject to certain permitted encumbrances and exceptions. Each mortgage also constitutes a lien on subsequently acquired property. At December 31, 2009, PEC and PEF had a total of $3.194 billion and $4.041 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. GUARANTEES OF SUBSIDIARY DEBT

See Note 18 on related party transactions for a discussion of obligations guaranteed or secured by affiliates.

E. HEDGING ACTIVITIES

We use interest rate derivatives to adjust the fixed and variable rate components of our debt portfolio and to hedge cash flow risk related to commercial paper and fixed-rate debt to be issued in the future. See Note 17 for a discussion of risk management activities and derivative transactions.

12. INVESTMENTS

A. INVESTMENTS

At December 31, 2009 and 2008, we had investments in various debt and equity securities, cost investments, company-owned life insurance and investments held in trust funds as follows:

	Progress Energy		PEC		PEF	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Nuclear decommissioning trust (See Notes 4C and 13)	**$1,367**	$1,089	**$871**	$672	**$496**	$417
Equity method investments(a)	**18**	22	**5**	9	**2**	2
Cost investments(b)	**5**	7	**4**	3	**–**	–
Company-owned life insurance(c)	**45**	49	**35**	34	**–**	–
Benefit investment trusts(d)	**191**	184	**90**	85	**35**	30
Marketable debt securities	**–**	1	**–**	1	**–**	–
Total	**$1,626**	$1,352	**$1,005**	$804	**$533**	$449

(a) Investments in unconsolidated companies are accounted for using the equity method of accounting (See Note 1) and are included in miscellaneous other property and investments in the Consolidated Balance Sheets. These investments are primarily in limited liability corporations and limited partnerships, and the earnings from these investments are recorded on a pre-tax basis.

(b) Investments stated principally at cost are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

(c) Investments in company-owned life insurance approximate fair value due to the nature of the investment and are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

(d) Benefit investment trusts are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 2009 and 2008, $152 million and $142 million, respectively, of investments in company-owned life insurance were held in Progress Energy's trusts. Substantially all of PEC's and PEF's benefit investment trusts are invested in company-owned life insurance.

B. IMPAIRMENT OF INVESTMENTS

We evaluate declines in value of investments under the criteria of GAAP. Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in long-term regulatory liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the

Consolidated Statements of Income for securities in our benefit investment trusts, other available-for-sale securities and equity and cost method investments. See Note 13 for additional information. There were no material other-than-temporary impairments in 2009, 2008 or 2007.

13. FAIR VALUE DISCLOSURES

A. DEBT AND INVESTMENTS

PROGRESS ENERGY

DEBT

The carrying amount of our long-term debt, including current maturities, was $12.457 billion and $10.659 billion at December 31, 2009 and 2008, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $13.4 billion and $11.3 billion at December 31, 2009 and 2008, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. Our available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning the Utilities' nuclear plants (See Note 4C). NDT funds are presented on the Consolidated Balance Sheets at fair value. In addition to the NDT funds, we hold other debt investments classified as available-for-sale, which are included in miscellaneous other property and investments on the Consolidated Balance Sheets at fair value.

The following table summarizes our available-for-sale securities at December 31, 2009 and 2008.

2009 **(in millions)**	**Unrealized Losses**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$(22)**	**$306**	**$855**
Corporate debt securities	**(1)**	**5**	**71**
U.S. state and municipal debt securities	**(2)**	**3**	**118**
U.S. and foreign government debt securities	**(1)**	**8**	**197**
Money market funds and other securities	**–**	**–**	**161**
Total	**$(26)**	**$322**	**$1,402**

2008 (in millions)	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$(93)	$134	$559
Corporate debt securities	(5)	–	53
U.S. state and municipal debt securities	(19)	4	233
U.S. and foreign government debt securities	(2)	11	171
Money market funds and other securities	(1)	–	123
Total	$(120)	$149	$1,139

The NDT funds and other available-for-sale debt investments held in certain benefit trusts are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities (See Note

7A) pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments; all of the unrealized losses and unrealized gains for 2009, and $118 million of the unrealized losses and $148 million of the unrealized gains for 2008, relate to the NDT funds. There were no material unrealized losses for the other available-for-sale debt securities held in benefit trusts at December 31, 2009 and 2008.

The aggregate fair value of investments that related to the 2009 and 2008 unrealized losses was $209 million and $374 million, respectively.

At December 31, 2009, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$12
Due after one through five years	180
Due after five through 10 years	122
Due after 10 years	84
Total	$398

The following table presents selected information about our sales of available-for-sale securities during the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2009**	2008	2007
Proceeds	**$1,275**	$1,092	$1,334
Realized gains	**26**	29	35
Realized losses	**87**	86	23

Previously, we invested available cash balances in various financial instruments, such as tax-exempt debt securities. For the year ended December 31, 2007, our proceeds from the sale of these securities were $399 million. For the years ended December 31, 2009 and 2008, our proceeds were primarily related to nuclear decommissioning trusts. Some of our benefit investment trusts are managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2009, 2008 and 2007 for investments in these benefit investment trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2009 and 2008, our other securities had no investments in a continuous loss position for greater than 12 months.

PEC

DEBT

The carrying amount of PEC's long-term debt, including current maturities, was $3.709 billion and $3.509 billion at December 31, 2009 and 2008, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $4.0 billion and $3.7 billion at December 31, 2009 and 2008, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. PEC's available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning PEC's nuclear plants (See Note 4C). NDT funds are presented on the Consolidated Balance Sheets at fair value.

The following table summarizes PEC's available-for-sale securities at December 31, 2009 and 2008.

2009 (in millions)	**Unrealized Losses**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$(19)**	**$189**	**$555**
Corporate debt securities	**(1)**	**4**	**67**
U.S. state and municipal debt securities	**–**	**1**	**37**
U.S. and foreign government debt securities	**(1)**	**8**	**177**
Money market funds and other securities	**–**	**–**	**35**
Total	**$(21)**	**$202**	**$871**

2008 (in millions)	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$(55)	$75	$334
Corporate debt securities	(2)	–	37
U.S. state and municipal debt securities	(6)	1	61
U.S. and foreign government debt securities	(1)	10	146
Money market funds and other securities	(1)	–	111
Total	$(65)	$86	$689

The NDT funds are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities (See Note 7A) pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and gains for 2009 and 2008 relate to the NDT funds.

The aggregate fair value of investments that related to the 2009 and 2008 unrealized losses was $121 million and $191 million, respectively.

At December 31, 2009, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$8
Due after one through five years	142
Due after five through 10 years	93
Due after 10 years	44
Total	$287

The following table presents selected information about PEC's sales of available-for-sale securities during the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2009**	2008	2007
Proceeds	**$602**	$579	$609
Realized gains	**9**	12	12
Realized losses	**36**	48	13

PEC's proceeds were primarily related to NDT funds. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2009 and 2008, PEC did not have any other securities.

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $4.183 billion and $4.182 billion at December 31, 2009 and 2008, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $4.5 billion at December 31, 2009 and 2008.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. PEF's available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning PEF's nuclear plant (See Note 4C). The NDT funds are presented on the Balance Sheets at fair value.

The following table summarizes PEF's available-for-sale securities at December 31, 2009 and 2008.

2009 **(in millions)**	**Unrealized Losses**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$(3)**	**$117**	**$300**
Corporate debt securities	**–**	**1**	**4**
U.S. state and municipal debt securities	**(2)**	**2**	**80**
U.S. and foreign government debt securities	**–**	**–**	**13**
Money market funds and other securities	**–**	**–**	**99**
Total	**$(5)**	**$120**	**$496**

2008 (in millions)	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$(38)	$59	$225
Corporate debt securities	(2)	–	7
U.S. state and municipal debt securities	(13)	3	168
U.S. and foreign government debt securities	–	–	1
Money market funds and other securities	–	–	10
Total	$(53)	$62	$411

The NDT funds are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities (See Note 7A) pursuant to ratemaking treatment. Therefore, the preceding tables include unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and gains for 2009 and 2008 relate to the NDT funds.

The aggregate fair value of investments that related to the 2009 and 2008 unrealized losses was $56 million and $165 million, respectively.

At December 31, 2009, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$4
Due after one through five years	35
Due after five through 10 years	27
Due after 10 years	33
Total	$99

The following table presents selected information about PEF's sales of available-for-sale securities for the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2009**	2008	2007
Proceeds	**$559**	$394	$535
Realized gains	**14**	16	22
Realized losses	**50**	36	9

Previously, PEF invested available cash balances in various financial instruments, such as tax-exempt debt securities. For the year ended December 31, 2007, PEF's proceeds from the sale of these securities were $329 million. For the years ended December 31, 2009 and 2008, all of PEF's proceeds were related to NDT. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2009 and 2008, PEF did not have any other securities.

B. FAIR VALUE MEASUREMENTS

GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Fair value measurements require the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs. A midmarket pricing convention (the midpoint price between bid and ask prices) is permitted for use as a practical expedient.

GAAP also establishes a fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

Level 1 – The pricing inputs are unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities.

Level 2 – The pricing inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 2 includes financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives, such as over-the-counter forwards, swaps and options; certain marketable debt securities; and financial instruments traded in less than active markets.

Level 3 – The pricing inputs include significant inputs generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments may include longer-term instruments that extend into periods where quoted prices or other observable inputs are not available.

The following tables set forth, by level within the fair value hierarchy, our and the Utilities' financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Progress Energy (in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds				
Equity	$855	$–	$–	$855
Corporate debt	–	71	–	71
U.S. state and municipal debt	–	117	–	117
U.S. and foreign government debt	62	128	–	190
Money market funds and other	1	133	–	134
Total nuclear decommissioning trust funds	918	449	–	1,367
Commodity and interest rate derivatives	–	39	–	39
Other marketable securities				
U.S. state and municipal debt	–	1	–	1
U.S. and foreign government debt	–	7	–	7
Money market and other	16	27	–	43
Total assets	$934	$523	$–	$1,457
Liabilities				
Commodity and interest rate derivatives	$–	$(386)	$(39)	$(425)
CVO derivatives	–	(15)	–	(15)
Total liabilities	$–	$(401)	$(39)	$(440)

PEC (in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds				
Equity	$555	$–	$–	$555
Corporate debt	–	67	–	67
U.S. state and municipal debt	–	37	–	37
U.S. and foreign government debt	52	125	–	177
Money market and other	1	34	–	35
Total nuclear decommissioning trust funds	608	263	–	871
Commodity and interest rate derivatives	–	8	–	8
Other marketable securities	1	–	–	1
Total assets	$609	$271	$–	$880
Liabilities				
Commodity and interest rate derivatives	$–	$(63)	$(27)	$(90)

PEF

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds				
Equity	$300	$–	$–	$300
Corporate debt	–	4	–	4
U.S. state and municipal debt	–	80	–	80
U.S. and foreign government debt	10	3	–	13
Money market funds and other	–	99	–	99
Total nuclear decommissioning trust funds	310	186	–	496
Commodity and interest rate derivatives	–	25	–	25
Other marketable securities	1	–	–	1
Total assets	$311	$211	$–	$522
Liabilities				
Commodity and interest rate derivatives	$–	$(323)	$(12)	$(335)

The determination of the fair values above incorporates various factors, including risks of nonperformance by us or our counterparties. Such risks consider not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits or letters of credit), but also the impact of our and the Utilities' credit risk on our liabilities.

Commodity and interest rate derivatives reflect positions held by us and the Utilities. Most over-the-counter commodity and interest rate derivatives are valued using financial models which utilize observable inputs for similar instruments and are classified within Level 2. Other derivatives are valued utilizing inputs that are not observable for substantially the full term of the contract, or for which the impact of the unobservable period is significant to the fair value of the derivative. Such derivatives are classified within Level 3. See Note 17 for discussion of risk management activities and derivative transactions.

NDT funds reflect the assets of the Utilities' nuclear decommissioning trusts. The assets of the trusts are invested primarily in exchange-traded equity securities (classified within Level 1) and marketable debt securities, most of which are valued using Level 1 inputs for similar instruments and are classified within Level 2.

Other marketable securities primarily represent available-for-sale debt securities used to fund certain employee benefit costs.

We issued Contingent Value Obligations (CVOs) in connection with the acquisition of Florida Progress, as discussed in Note 15. The CVOs are derivatives recorded at fair value based on quoted prices from a less-than-active market and are classified as Level 2.

The following tables set forth a reconciliation of changes in the fair value of our and the Utilities' commodity derivatives classified as Level 3 in the fair value hierarchy for the 12 months ended December 31, 2009.

Progress Energy

(in millions)	
Derivatives, net at January 1, 2009	$(41)
Total gains (losses), realized and unrealized	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(13)
Purchases, issuances and settlements, net	–
Transfers in (out) of Level 3, net	15
Derivatives, net at December 31, 2009	$(39)

PEC

(in millions)	
Derivatives, net at January 1, 2009	$(22)
Total gains (losses), realized and unrealized	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(7)
Purchases, issuances and settlements, net	–
Transfers in (out) of Level 3, net	2
Derivatives, net at December 31, 2009	$(27)

PEF

(in millions)	
Derivatives, net at January 1, 2009	$(19)
Total gains (losses), realized and unrealized	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(6)
Purchases, issuances and settlements, net	–
Transfers in (out) of Level 3, net	13
Derivatives, net at December 31, 2009	$(12)

Substantially all unrealized gains and losses on derivatives are deferred as regulatory liabilities or assets consistent with ratemaking treatment.

Transfers in (out) of Level 3 represent existing assets or liabilities that were previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period. Transfers into Level 3 are measured at the beginning of the period, and transfers out of Level 3 are measured at the end of the period.

14. INCOME TAXES

We provide deferred income taxes for temporary differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to GAAP for regulated operations. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount that, in our judgment, is greater than 50 percent likely to be realized.

PROGRESS ENERGY

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	**2009**	2008
Deferred income tax assets		
ARO liability	**$127**	$264
Derivative instruments	**159**	298
Income taxes refundable through future rates	**225**	111
Pension and other postretirement benefits	**508**	544
Other	**374**	340
Federal income tax credit carry forward	**712**	802
State net operating loss carry forward (net of federal expense)	**66**	64
Valuation allowance	**(55)**	(55)
Total deferred income tax assets	**2,116**	2,368
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,889)**	(1,665)
Deferred fuel recovery	**(74)**	(186)
Income taxes recoverable through future rates	**(782)**	(959)
Other	**(264)**	(141)
Total deferred income tax liabilities	**(3,009)**	(2,951)
Total net deferred income tax liabilities	**$(893)**	$(583)

The above amounts were classified on the Consolidated Balance Sheets as follows:

(in millions)	**2009**	2008
Current deferred income tax assets, included in prepayments and other current assets	**$168**	$96
Noncurrent deferred income tax assets, included in other assets and deferred debits	**37**	32
Current deferred income tax liabilities, included in other current liabilities	**–**	(1)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(1,098)**	(710)
Total net deferred income tax liabilities	**$(893)**	$(583)

At December 31, 2009, the federal income tax credit carry forward includes $712 million of alternative minimum tax credits that do not expire.

At December 31, 2009, we had gross state net operating loss carry forwards of $1.6 billion that will expire during the period 2010 through 2029.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We had a net increase of less than $1 million in our valuation allowances during 2009.

We believe it is more likely than not that the results of future operations will generate sufficient taxable income to allow for the utilization of the remaining deferred tax assets.

Reconciliations of our effective income tax rate to the statutory federal income tax rate for the years ended December 31 follow:

	2009	2008	2007
Effective income tax rate	**32.1%**	33.7%	32.3%
State income taxes, net of federal benefit	**(3.7)**	(3.8)	(2.8)
Investment tax credit amortization	**0.8**	1.0	1.1
Employee stock ownership plan dividends	**1.0**	1.0	1.1
Domestic manufacturing deduction	**0.8**	0.3	1.0
AFUDC equity	**2.2**	2.5	0.7
Other differences, net	**1.8**	0.3	1.6
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense applicable to continuing operations for the years ended December 31 was comprised of:

(in millions)	**2009**	2008	2007
Current – federal	**$227**	$38	$285
– state	**41**	12	36
Deferred – federal	**114**	305	13
– state	**25**	49	11
Investment tax credit	**(10)**	(12)	(12)
State net operating loss carry forward	–	(6)	1
Beginning-of-the-year valuation allowance change	–	9	–
Total income tax expense	**$397**	$395	$334

We previously recorded a deferred income tax asset for a state net operating loss carry forward upon the sale of PVI's nonregulated generation facilities and energy marketing and trading operations. During 2008, we recorded an additional deferred income tax asset of $6 million related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings. During 2008 we also evaluated this state net operating loss carry forward and recorded a partial valuation allowance of $9 million.

Total income tax expense applicable to continuing operations excluded the following:

- Taxes related to discontinued operations recorded net of tax for 2009, 2008 and 2007, which are presented separately in Notes 3A through 3E.
- Taxes related to other comprehensive income recorded net of tax for 2009, 2008 and 2007, which are presented separately in the Consolidated Statements of Comprehensive Income.
- Current tax benefit of $6 million, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2009 and 2008.

- Taxes of $2 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting new guidance for uncertain tax positions on January 1, 2007.

At December 31, 2009, 2008 and 2007, our liability for unrecognized tax benefits was $160 million, $104 million and $93 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $9 million, $8 million and $10 million, respectively, at December 31, 2009, 2008 and 2007. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2009, 2008 and 2007:

(in millions)	**2009**	2008	2007
Unrecognized tax benefits at beginning of period	**$104**	$93	$126
Gross amounts of increases as a result of tax positions taken in a prior period	**11**	17	32
Gross amounts of decreases as a result of tax positions taken in a prior period	**(3)**	(11)	(41)
Gross amounts of increases as a result of tax positions taken in the current period	**52**	8	22
Gross amounts of decreases as a result of tax positions taken in the current period	**(4)**	(2)	(32)
Amounts of net increases (decreases) relating to settlements with taxing authorities	**–**	1	(14)
Reductions as a result of a lapse of the applicable statute of limitations	**–**	(2)	–
Unrecognized tax benefits at end of period	**$160**	$104	$93

We and our subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Our open federal tax years are from 2004 forward, and our open state tax years in our major jurisdictions are generally from 2003 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when the review will be completed. Although the timing for completion of the IRS' review is uncertain, it is reasonably possible that unrecognized tax benefits will decrease by up to approximately $60 million during the 12-month period ending December 31, 2010, due to expected settlements. Any potential decrease will not have a material impact on our results of operations.

We include interest expense related to unrecognized tax benefits in interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2009, 2008 and 2007, the net interest expense related to unrecognized tax benefits was $9 million, $4 million and $1 million, respectively, of which a respective $5 million, $1 million and $15 million expense component was deferred as a regulatory asset by PEF, which is amortized as a charge to interest expense over a three-year period or less. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2009 and 2007, there were no penalties related to unrecognized tax benefits. During 2008, less than $1 million was recorded for penalties related to unrecognized tax benefits. At December 31, 2009 and 2008, we had accrued $36 million and $27 million, respectively, for interest and penalties, which are included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

PEC

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	2009	2008
Deferred income tax assets		
ARO liability	**$111**	$244
Derivative instruments	**37**	64
Income taxes refundable through future rates	**106**	10
Pension and other postretirement benefits	**254**	262
Other	**149**	108
Total deferred income tax assets	**657**	688
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,307)**	(1,162)
Deferred fuel recovery	**(60)**	(132)
Income taxes recoverable through future rates	**(377)**	(451)
Investments	**(71)**	(8)
Other	**(8)**	(12)
Total deferred income tax liabilities	**(1,823)**	(1,765)
Total net deferred income tax liabilities	**$(1,166)**	$(1,077)

The above amounts were classified on the Consolidated Balance Sheets as follows:

(in millions)	2009	2008
Current deferred income tax assets, included in prepayments and other current assets	**$42**	$–
Current deferred income tax liabilities, included in other current liabilities	**–**	(5)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(1,208)**	(1,072)
Total net deferred income tax liabilities	**$(1,166)**	$(1,077)

Reconciliations of PEC's effective income tax rate to the statutory federal income tax rate for the years ended December 31 follow:

	2009	2008	2007
Effective income tax rate	**35.0%**	35.8%	37.1%
State income taxes, net of federal benefit	**(2.8)**	(2.7)	(2.3)
Investment tax credit amortization	**0.7**	0.7	0.7
Domestic manufacturing deduction	**0.9**	0.5	1.1
Other differences, net	**1.2**	0.7	(1.6)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense for the years ended December 31 was comprised of:

(in millions)	**2009**	2008	2007
Current – federal	**$192**	$87	$235
– state	**21**	7	19
Deferred – federal	**57**	181	34
– state	**13**	29	13
Investment tax credit	**(6)**	(6)	(6)
Total income tax expense	**$277**	$298	$295

Total income tax expense excluded the following:

- Taxes related to other comprehensive income recorded net of tax for 2009, 2008 and 2007, which are presented separately in the Consolidated Statements of Comprehensive Income.
- Current tax benefit of $3 million, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2009 and 2008.
- Taxes of $6 million that reduced retained earnings, due to the cumulative effect of adopting new guidance for uncertain tax positions on January 1, 2007.

PEC and each of its wholly owned subsidiaries have entered into the Tax Agreement with the Parent (See Note 1D). PEC's intercompany tax receivable was approximately $38 million and $74 million at December 31, 2009 and 2008, respectively.

At December 31, 2009, 2008 and 2007, PEC's liability for unrecognized tax benefits was $59 million, $38 million and $41 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $5 million, $5 million and $9 million, respectively, at December 31, 2009, 2008 and 2007. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2009, 2008 and 2007:

(in millions)	**2009**	2008	2007
Unrecognized tax benefits at beginning of period	**$38**	$41	$43
Gross amounts of increases as a result of tax positions taken in a prior period	**6**	5	3
Gross amounts of decreases as a result of tax positions taken in a prior period	**(2)**	(10)	(15)
Gross amounts of increases as a result of tax positions taken in the current period	**17**	4	22
Gross amounts of decreases as a result of tax positions taken in the current period	**–**	(1)	(5)
Amounts of net increases (decreases) relating to settlements with taxing authorities	**–**	1	(7)
Reductions as a result of a lapse of the applicable statute of limitations	**–**	(2)	–
Unrecognized tax benefits at end of period	**$59**	$38	$41

We file consolidated federal and state income tax returns that include PEC. In addition, PEC files stand-alone tax returns in various state jurisdictions. PEC's open federal tax years are from 2004 forward, and PEC's open state tax years in our major jurisdictions are generally from 2003 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. PEC cannot predict when the review will be completed. Although the timing for completion of the IRS' review is uncertain, it is reasonably possible that PEC's unrecognized tax benefits will decrease by up to approximately $10 million during the 12-month period ending December 31, 2010, due to expected settlements. Any potential decrease will not have a material impact on PEC's results of operations.

PEC includes interest expense related to unrecognized tax benefits in interest charges and includes penalties in other, net on the Consolidated Statements of Income. During 2009 the interest expense recorded related to unrecognized tax benefits was $3 million.

During 2008 and 2007, the interest benefit recorded related to unrecognized tax benefits was $1 million and $4 million, respectively. During 2009, 2008 and 2007, there were no penalties recorded related to unrecognized tax benefits. At December 31, 2009 and 2008, PEC had accrued $10 million and $7 million, respectively, for interest and penalties, which are included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

PEF

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	**2009**	2008
Deferred income tax assets		
Derivative instruments	**$125**	$222
Income taxes refundable through future rates	**73**	54
Pension and other postretirement benefits	**163**	192
Reserve for storm damage	**52**	54
Unbilled revenue	**48**	43
Other	**89**	101
Total deferred income tax assets	**550**	666
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(568)**	(490)
Deferred fuel recovery	**(14)**	(54)
Deferred nuclear cost recovery	**(107)**	(73)
Income taxes recoverable through future rates	**(406)**	(508)
Investments	**(44)**	(3)
Other	**(26)**	(36)
Total deferred income tax liabilities	**(1,165)**	(1,164)
Total net deferred income tax liabilities	**$(615)**	$(498)

The above amounts were classified on the Balance Sheets as follows:

(in millions)	**2009**	2008
Current deferred income tax assets, included in deferred income taxes	**$115**	$74
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(730)**	(572)
Total net deferred income tax liabilities	**$(615)**	$(498)

Reconciliations of PEF's effective income tax rate to the statutory federal income tax rate for the years ended December 31 follow:

	2009	2008	2007
Effective income tax rate	**31.1%**	32.0%	31.2%
State income taxes, net of federal benefit	**(3.0)**	(3.1)	(3.3)
Investment tax credit amortization	**0.7**	1.1	1.3
Domestic manufacturing deduction	**0.8**	0.2	0.8
AFUDC equity	**3.4**	5.4	2.6
Other differences, net	**2.0**	(0.6)	2.4
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense for the years ended December 31 was comprised of:

(in millions)	**2009**	2008	2007
Current – federal	**$125**	$39	$160
– state	**20**	12	28
Deferred – federal	**57**	121	(33)
– state	**11**	15	(5)
Investment tax credit	**(4)**	(6)	(6)
Total income tax expense	**$209**	$181	$144

Total income tax expense excluded the following:

- Taxes related to other comprehensive income recorded net of tax for 2009, 2008 and 2007, which are presented separately in the Statements of Comprehensive Income.
- Less than $1 million of current tax benefit, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2009 and 2008.
- Taxes of less than $1 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting new guidance for uncertain tax positions on January 1, 2007.

PEF has entered into the Tax Agreement with the Parent (See Note 1D). PEF's intercompany tax receivable was approximately $122 million and $47 million at December 31, 2009 and 2008, respectively.

At December 31, 2009, 2008 and 2007, PEF's liability for unrecognized tax benefits was $98 million, $62 million and $55 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $3 million, $2 million and $3 million, respectively, at December 31, 2009, 2008 and 2007. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2009, 2008 and 2007:

(in millions)	**2009**	2008	2007
Unrecognized tax benefits at beginning of period	**$62**	$55	$72
Gross amounts of increases as a result of tax positions taken in a prior period	**5**	6	23
Gross amounts of decreases as a result of tax positions taken in a prior period	**(1)**	(1)	(4)
Gross amounts of increases as a result of tax positions taken in the current period	**35**	3	2
Gross amounts of decreases as a result of tax positions taken in the current period	**(3)**	(1)	(25)
Amounts of decreases relating to settlements with taxing authorities	**–**	–	(13)
Reductions as a result of a lapse of the applicable statute of limitations	**–**	–	–
Unrecognized tax benefits at end of period	**$98**	$62	$55

We file consolidated federal and state income tax returns that include PEF. PEF's open federal tax years are from 2004 forward and PEF's open state tax years are generally from 2003 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. PEF cannot predict when the review will be completed. Although the timing for completion of the IRS' review is uncertain, it is reasonably possible that PEF's unrecognized tax benefits will decrease by up to approximately $50 million during the 12-month period ending December 31, 2010, due to expected settlements. Any potential decrease will not have a material impact on PEF's results of operations.

Pursuant to a regulatory order, PEF records interest expense related to unrecognized tax benefits as a regulatory asset, which is amortized over a three-year period or less, with the amortization included in interest charges on the Statements of Income. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense on the Statement of Income. Penalties are included in other, net on the Statements of Income. During 2009, 2008 and 2007, interest expense recorded as a regulatory asset was $5 million, $1 million and $15 million, respectively, and there were no penalties recorded related to unrecognized tax benefits. At December 31, 2009 and 2008, PEF had accrued $24 million and $19 million, respectively, for interest and penalties, which are included in interest accrued and other assets and deferred debits on the Balance Sheets.

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four coal-based solid synthetic fuels limited liability companies, of which three were wholly owned (Earthco), purchased by subsidiaries of Florida Progress in October 1999. All of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007 (See Note 3A). The payments are based on the net after-tax cash flows the facilities generate. We will make deposits into a CVO trust for estimated contingent payments due to CVO holders based on the results of operations and the utilization of tax credits. Monies held in the trust are generally not payable to the CVO holders until the completion of income tax audits. The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income (See Note 20). At December 31, 2009 and 2008, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million and $34 million, respectively.

During the year ended December 31, 2008, a $6 million deposit was made into the CVO trust for the CVO holders' share of the disposition proceeds from the sale of one of the Earthco synthetic fuels facilities (See Note 3E). Disposition proceeds payments will not generally be made to CVO holders until the termination of all indemnity obligations under the purchase and sale agreement related to the disposition. Future payments will include principal and interest earned during the investment period net of expenses deducted. The interest earned on the payments held in trust for 2009 and 2008 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheet at December 31, 2009 and 2008.

16. BENEFIT PLANS

A. POSTRETIREMENT BENEFITS

We have noncontributory defined benefit retirement plans that provide pension benefits for substantially all full-time employees. We also have supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, we provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. We use a measurement date of December 31 for our pension and OPEB plans.

COSTS OF BENEFIT PLANS

Prior service costs and benefits are amortized on a straight-line basis over the average remaining service period of active participants. Actuarial gains and losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

To determine the market-related value of assets, we use a five-year averaging method for a portion of the pension assets and fair value for the remaining portion. We have historically used the five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets.

The tables below provide the components of the net periodic benefit cost for 2009, 2008 and 2007. A portion of net periodic benefit cost is capitalized as part of construction work in progress.

Progress Energy

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Service cost	**$42**	$46	$46	**$7**	$8	$7
Interest cost	**138**	128	123	**31**	34	32
Expected return on plan assets	**(133)**	(170)	(155)	**(4)**	(6)	(6)
Amortization of actuarial loss[a]	**54**	8	15	**1**	1	2
Other amortization, net[a]	**6**	2	2	**5**	5	5
Net periodic cost before deferral[b]	**$107**	$14	$31	**$40**	$42	$40

(a) Adjusted to reflect PEF's rate treatment (See Note 16B).

(b) In June 2009, PEF received permission from the FPSC to defer the retail portion of certain pension expense in 2009. The FPSC order did not change the total net periodic pension cost, but defers a portion of these costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension cost as a regulatory asset (see Note 7C).

PEC

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Service cost	**$18**	$23	$23	**$5**	$5	$5
Interest cost	**64**	58	56	**16**	17	15
Expected return on plan assets	**(67)**	(66)	(60)	**(2)**	(4)	(4)
Amortization of actuarial loss	**11**	6	12	**–**	–	–
Other amortization, net	**6**	2	2	**1**	1	1
Net periodic cost	**$32**	$23	$33	**$20**	$19	$17

PEF

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Service cost	**$19**	$17	$16	**$2**	$2	$2
Interest cost	**56**	53	52	**13**	14	14
Expected return on plan assets	**(56)**	(90)	(84)	**(1)**	(1)	(1)
Amortization of actuarial loss	**38**	1	1	**–**	1	2
Other amortization, net	**–**	(1)	(1)	**3**	3	3
Net periodic cost (benefit) before deferral[a]	**$57**	$(20)	$(16)	**$17**	$19	$20

(a) In June 2009, PEF received permission from the FPSC to defer the retail portion of certain pension expense in 2009. The FPSC order did not change the total net periodic pension cost, but defers a portion of these costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension cost as a regulatory asset (see Note 7C).

The tables below provide a summary of amounts recognized in other comprehensive income and other comprehensive income reclassification adjustments for amounts included in net income, for 2009, 2008 and 2007. The tables also include comparable items that affected regulatory assets of PEC and PEF. For PEC and PEF, amounts that would otherwise be recorded in other comprehensive income are recorded as adjustments to regulatory assets consistent with the recovery of the related costs through the ratemaking process.

Progress Energy

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Other comprehensive income (loss)						
Recognized for the year						
Net actuarial (loss) gain	**$(1)**	$(64)	$24	**$4**	$(8)	$16
Other, net	**–**	(6)	(1)	**–**	–	–
Reclassification adjustments						
Net actuarial loss	**5**	1	2	**1**	–	–
Other, net	**–**	1	1	**1**	–	–
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial gain (loss)	**10**	(735)	66	**64**	(73)	82
Other, net	**(3)**	(36)	(8)	**–**	–	–
Amortized to income[(a)]						
Net actuarial loss	**49**	7	13	**–**	1	2
Other, net	**6**	1	1	**4**	5	4

(a) These amounts were amortized as a component of net periodic cost, as reflected in the previous net periodic cost table. Refer to that table for information regarding the deferral of a portion of net periodic pension cost.

PEC

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	**$(14)**	$(308)	$26	**$38**	$(66)	$82
Other, net	**(2)**	(31)	(6)	**–**	–	–
Amortized to net income						
Net actuarial loss	**11**	6	12	**–**	–	–
Other, net	**6**	2	2	**1**	1	1

PEF

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial gain (loss)	**$24**	$(427)	$40	**$26**	$(6)	$–
Other, net	**(1)**	(5)	(1)	**–**	–	–
Amortized to net income[(a)]						
Net actuarial loss	**38**	1	1	**–**	1	2
Other, net	**–**	(1)	(1)	**3**	3	3

(a) These amounts were amortized as a component of net periodic cost, as reflected in the previous net periodic cost table. Refer to that table for information regarding the deferral of a portion of net periodic pension cost.

The following weighted-average actuarial assumptions were used by Progress Energy in the calculation of its net periodic cost:

	Pension Benefits			Other Postretirement Benefits		
	2009	2008	2007	**2009**	2008	2007
Discount rate	**6.30%**	6.20%	5.95%	**6.20%**	6.20%	5.95%
Rate of increase in future compensation						
Bargaining	**4.25%**	4.25%	4.25%	**–**	–	–
Supplementary plans	**5.25%**	5.25%	5.25%	**–**	–	–
Expected long-term rate of return on plan assets	**8.75%**	9.00%	9.00%	**6.80%**	8.10%	7.70%

The weighted-average actuarial assumptions used by PEC and PEF were not materially different from the assumptions above, as applicable, except that the expected long-term rate of return on OPEB plan assets was 5.00% for PEF for all years presented and for PEC was 8.75%, 9.00% and 9.00% for 2009, 2008 and 2007, respectively.

The expected long-term rates of return on plan assets were determined by considering long-term projected returns based on the plans' target asset allocations. Specifically, return rates were developed for each major asset class and weighted based on the target asset allocations. The projected returns were benchmarked against historical returns for reasonableness. We decreased our expected long-term rate of return on pension assets by 0.25% in 2009, primarily due to the uncertainties resulting from the severe capital market deterioration in 2008. See the "Assets of Benefit Plans" section below for additional information regarding our investment policies and strategies.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

GAAP requires us to recognize in our statement of financial condition the funded status of our pension and other postretirement benefit plans, measured as the difference between the fair value of the plan assets and the benefit obligation as of the end of the fiscal year.

Reconciliations of the changes in the Progress Registrants' benefit obligations and the funded status as of December 31, 2009 and 2008 are presented in the tables below, with each table followed by related supplementary information.

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Projected benefit obligation at January 1	**$2,234**	$2,142	**$608**	$541
Service cost	**42**	46	**7**	8
Interest cost	**138**	128	**31**	34
Settlements	**(9)**	–	**–**	–
Benefit payments	**(124)**	(127)	**(40)**	(35)
Plan amendment	**3**	42	**–**	–
Actuarial loss (gain)	**138**	3	**(63)**	60
Obligation at December 31	**2,422**	2,234	**543**	608
Fair value of plan assets at December 31	**1,673**	1,285	**55**	52
Funded status	**$(749)**	$(949)	**$(488)**	$(556)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.422 billion and $2.234 billion at December 31, 2009 and 2008, respectively. Those plans had accumulated benefit obligations totaling $2.378 billion and $2.196 billion at December 31, 2009 and 2008, respectively, and plan assets of $1.673 billion and $1.285 billion at December 31, 2009 and 2008, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Current liabilities	**(9)**	(10)	**$–**	$(1)
Noncurrent liabilities	**(740)**	(939)	**(488)**	(555)
Funded status	**$(749)**	$(949)	**$(488)**	$(556)

The table below provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	**$83**	$87	**$(5)**	$–
Other, net	**10**	11	**–**	–
Recognized in regulatory assets, net				
Net actuarial loss	**806**	865	**32**	97
Other, net	**59**	62	**14**	18
Total not yet recognized as a component of net periodic cost[(a)]	**$958**	$1,025	**$41**	$115

(a) All components are adjusted to reflect PEF's rate treatment (See Note 16B).

The following table presents the amounts we expect to recognize as components of net periodic cost in 2010.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss [(a)]	$50	$1
Amortization of other, net[(a)]	6	5

(a) Adjusted to reflect PEF's rate treatment (See Note 16B).

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Projected benefit obligation at January 1	**$1,025**	$980	**$312**	$257
Service cost	**18**	23	**5**	5
Interest cost	**64**	58	**16**	17
Plan amendment	**2**	31	**–**	–
Benefit payments	**(50)**	(55)	**(17)**	(15)
Actuarial loss (gain)	**61**	(12)	**(34)**	48
Obligation at December 31	**1,120**	1,025	**282**	312
Fair value of plan assets at December 31	**749**	521	**21**	22
Funded status	**$(371)**	$(504)	**$(261)**	$(290)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $1.120 billion and $1.025 billion at December 31, 2009 and 2008, respectively. Those plans had accumulated benefit obligations totaling $1.116 billion and $1.021 billion at December 31, 2009 and 2008, respectively, and plan assets of $749 million and $521 million at December 31, 2009 and 2008, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Current liabilities	**$(2)**	$(2)	**$ –**	$ –
Noncurrent liabilities	**(369)**	(502)	**(261)**	(290)
Funded status	**$(371)**	$(504)	**$(261)**	$(290)

The table below provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Recognized in regulatory assets				
Net actuarial loss	**$410**	$407	**$16**	$54
Other, net	**54**	57	**3**	4
Total not yet recognized as a component of net periodic cost	**$464**	$464	**$19**	$58

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2010.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	$16	$–
Amortization of other, net	6	1

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Projected benefit obligation at January 1	**$914**	$881	**$248**	$245
Service cost	**19**	17	**2**	2
Interest cost	**56**	53	**13**	14
Plan amendment	**–**	5	**–**	–
Benefit payments	**(58)**	(58)	**(20)**	(18)
Actuarial loss (gain)	**61**	16	**(24)**	5
Obligation at December 31	**992**	914	**219**	248
Fair value of plan assets at December 31	**794**	650	**32**	27
Funded status	**$(198)**	$(264)	**$(187)**	$(221)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $992 million and $914 million at December 31, 2009 and 2008, respectively. Those plans had accumulated benefit obligations totaling $957 million and $884 million at December 31, 2009 and 2008, respectively, and plan assets of $794 million and $650 million at December 31, 2009 and 2008, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Current liabilities	**$(3)**	$(3)	**$–**	$–
Noncurrent liabilities	**(195)**	(261)	**(187)**	(221)
Funded status	**$(198)**	$(264)	**$(187)**	$(221)

The table below provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Recognized in regulatory assets, net				
Net actuarial loss	**$396**	$458	**$16**	$43
Other, net	**5**	5	**11**	14
Total not yet recognized as a component of net periodic cost	**$401**	$463	**$27**	$57

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2010.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	$30	$1
Amortization of other, net	–	4

The following weighted-average actuarial assumptions were used in the calculation of our year-end obligations:

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	**2009**	2008
Discount rate	**6.00%**	6.30%	**6.05%**	6.20%
Rate of increase in future compensation				
Bargaining	**4.50%**	4.25%	–	–
Supplementary plans	**5.25%**	5.25%	–	–
Initial medical cost trend rate for pre-Medicare Act benefits	–	–	**8.50%**	9.00%
Initial medical cost trend rate for post-Medicare Act benefits	–	–	**8.50%**	9.00%
Ultimate medical cost trend rate	–	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	–	–	**2016**	2016

The weighted-average actuarial assumptions for PEC and PEF were the same or were not significantly different from those indicated above, as applicable. The rates of increase in future compensation include the effects of cost of living adjustments and promotions.

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan. Therefore, we use the traditional unit credit method for purposes of measuring the benefit obligation of this plan. Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. The effects of a 1 percent change in the medical cost trend rate are shown below.

(in millions)	Progress Energy	PEC	PEF
1 percent increase in medical cost trend rate			
Effect on total of service and interest cost	$2	$1	$1
Effect on postretirement benefit obligation	26	14	11
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(1)	(1)	–
Effect on postretirement benefit obligation	(21)	(11)	(9)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our, PEC's and PEF's employer contributions for 2009 include contributions directly to pension plan assets of $222 million, $163 million and $58 million, respectively, and for 2008 include contributions directly to pension plan assets of $33 million, $24 million and less than $1 million, respectively. Substantially all of the remaining employer contributions represent benefit payments made directly from the Progress Registrants' assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the cost after participant contributions. Participant contributions represent approximately 20 percent of gross benefit payments for Progress Energy, 25 percent for PEC and 15 percent for PEF. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2009, the subsidies totaled $3 million for us, $1 million for PEC and $1 million for PEF. In 2008, the subsidies totaled $3 million for us, $1 million for PEC and $2 million for PEF.

Reconciliations of the fair value of plan assets at December 31 follow:

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at January 1	**$1,285**	$1,996	**$52**	$75
Actual return on plan assets	**279**	(627)	**9**	(16)
Benefit payments, including settlements	**(133)**	(127)	**(40)**	(35)
Employer contributions	**242**	43	**34**	28
Fair value of plan assets at December 31	**$1,673**	$1,285	**$55**	$52

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at January 1	**$521**	$805	**$22**	$44
Actual return on plan assets	**113**	(255)	**5**	(14)
Benefit payments	**(50)**	(55)	**(17)**	(15)
Employer contributions	**165**	26	**11**	7
Fair value of plan assets at December 31	**$749**	$521	**$21**	$22

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at January 1	**$650**	$1,026	**$27**	$26
Actual return on plan assets	**141**	(321)	**3**	–
Benefit payments	**(58)**	(58)	**(20)**	(18)
Employer contributions	**61**	3	**22**	19
Fair value of plan assets at December 31	**$794**	$650	**$32**	$27

The Progress Registrants' primary objectives when setting investment policies and strategies are to manage the assets of the pension plan to ensure that sufficient funds are available at all times to finance promised benefits and to invest the funds such that contributions are minimized, within acceptable risk limits. We periodically perform studies to analyze various aspects of our pension plans including asset allocations, expected portfolio return, pension contributions and net funded status. One of our key investment objectives is to achieve a rolling 10-year annual return of 6 percent over the rate of inflation. The target pension asset allocations are 40 percent domestic equity, 20 percent international equity, 10 percent domestic fixed income, 15 percent global fixed income, 10 percent private equity and timber and 5 percent hedge funds. Tactical shifts (plus or minus 5 percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes. Domestic equity includes investments across large, medium and small capitalized domestic stocks, using investment managers with value, growth and core-based investment strategies. International equity includes investments in foreign stocks in both developed and emerging market countries, using a mix of value and growth based investment strategies. Domestic fixed income primarily includes domestic investment grade fixed income investments. Global fixed income includes domestic and foreign fixed income investments. A substantial portion of OPEB plan assets are managed with pension assets. The remaining OPEB plan assets, representing all PEF's OPEB plan assets, are invested in domestic governmental securities.

PROGRESS ENERGY

The following table sets forth by level within the fair value hierarchy of our pension and other postretirement plan assets as of December 31, 2009. See Note 13 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash and cash equivalents	$1	$96	$–	$97
Domestic equity securities	263	1	–	264
Private equity securities	–	–	122	122
Corporate bonds	–	67	–	67
U.S. state and municipal debt	–	4	–	4
U.S. and foreign government debt	25	95	–	120
Mortgage backed securities	–	22	–	22
Commingled funds	–	888	–	888
Hedge funds	–	47	2	49
Timber investments	–	–	14	14
Credit default swaps	–	20	–	20
Interest rate swaps and other investments	–	36	–	36
Total assets	$289	$1,276	$138	$1,703
Liabilities				
Foreign currency contracts	(5)	–	–	(5)
Credit default swaps	–	(20)	–	(20)
Interest rate swaps and other investments	–	(5)	–	(5)
Total liabilities	(5)	(25)	–	(30)
Fair value of plan assets	$284	$1,251	$138	$1,673

	Other Postretirement Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash and cash equivalents	$–	$1	$–	$1
Domestic equity securities	4	–	–	4
Corporate bonds	–	1	–	1
U.S. state and municipal debt	–	32	–	32
U.S. and foreign government debt	–	2	–	2
Commingled funds	–	13	–	13
Hedge funds	–	1	–	1
Interest rate swaps and other investments	–	1	–	1
Fair value of plan assets	$4	$51	$–	$55

The following table sets forth a reconciliation of changes in the fair value of our pension plan assets classified as Level 3 in the fair value hierarchy for the year ended December 31, 2009.

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
Balance at January 1	$111	$2	$18	$131
Net realized and unrealized (losses)[a]	(10)	–	(4)	(14)
Purchases, sales and distributions, net	21	–	–	21
Balance at December 31	$122	$2	$14	$138

(a) Substantially all amounts relate to investments held at December 31, 2009.

PEC

The following table sets forth by level within the fair value hierarchy of PEC's pension and other postretirement plan assets as of December 31, 2009. See Note 13 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	$–	$43	$–	$43
Domestic equity securities	118	–	–	118
Private equity securities	–	–	55	55
Corporate bonds	–	30	–	30
U.S. state and municipal debt	–	2	–	2
U.S. and foreign government debt	11	43	–	54
Mortgage backed securities	–	10	–	10
Commingled funds	–	398	–	398
Hedge funds	–	21	1	22
Timber investments	–	–	6	6
Credit default swaps	–	9	–	9
Interest rate swaps and other investments	–	15	–	15
Total assets	$129	$571	$62	$762
Liabilities				
Foreign currency contracts	(2)	–	–	(2)
Credit default swaps	–	(9)	–	(9)
Interest rate swaps and other investments	–	(2)	–	(2)
Total liabilities	(2)	(11)	–	(13)
Fair value of plan assets	$127	$560	$62	$749

	Other Postretirement Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash and cash equivalents	$–	$1	$–	$1
Domestic equity securities	4	–	–	4
Corporate bonds	–	1	–	1
U.S. and foreign government debt	–	2	–	2
Commingled funds	–	12	–	12
Hedge funds	–	1	–	1
Fair value of plan assets	$4	$17	$–	$21

The following table sets forth a reconciliation of changes in the fair value of PEC's pension plan assets classified as Level 3 in the fair value hierarchy for the year ended December 31, 2009.

(in millions)	**Private Equity Securities**	**Hedge Funds**	**Timber Investments**	**Total**
Balance at January 1	$49	$1	$8	$58
Net realized and unrealized (losses)[a]	(4)	–	(2)	(6)
Purchases, sales and distributions, net	10	–	–	10
Balance at December 31	$55	$1	$6	$62

(a) Substantially all amounts relate to investments held at December 31, 2009.

PEF

The following table sets forth by level within the fair value hierarchy of PEF's pension plan assets as of December 31, 2009. See Note 13 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash and cash equivalents	$–	$46	$–	$46
Domestic equity securities	125	–	–	125
Private equity securities	–	–	58	58
Corporate bonds	–	32	–	32
U.S. state and municipal debt	–	2	–	2
U.S. and foreign government debt	12	45	–	57
Mortgage backed securities	–	10	–	10
Commingled funds	–	421	–	421
Hedge funds	–	22	1	23
Timber investments	–	–	7	7
Credit default swaps	–	9	–	9
Interest rate swaps and other investments	–	17	–	17
Total assets	$137	$604	$66	$807
Liabilities				
Foreign currency contracts	(2)	–	–	(2)
Credit default swaps	–	(9)	–	(9)
Interest rate swaps and other investments	–	(2)	–	(2)
Total liabilities	(2)	(11)	–	(13)
Fair value of plan assets	$135	$593	$66	$794

PEF's other postretirement benefit plan assets had a fair value of $32 million which consisted of U.S. state and municipal assets classified as Level 2 in the fair value hierarchy as of December 31, 2009.

The following table sets forth a reconciliation of changes in the fair value of PEF's pension plan assets classified as Level 3 in the fair value hierarchy for the year ended December 31, 2009.

(in millions)	**Private Equity Securities**	**Hedge Funds**	**Timber Investments**	**Total**
Balance at January 1	$53	$1	$9	$63
Net realized and unrealized (losses)(a)	(5)	–	(2)	(7)
Purchases, sales and distributions, net	10	–	–	10
Balance at December 31	$58	$1	$7	$66

(a) Substantially all amounts relate to investments held at December 31, 2009.

For Progress Energy, PEC and PEF, the determination of the fair values of pension and postretirement plan assets incorporates various factors required under GAAP. The assets of the plan include exchange traded securities (classified within Level 1) and other marketable debt and equity securities, most of which are valued using Level 1 inputs for similar instruments, and are classified within

Level 2 investments.

Most over-the-counter investments are valued using observable inputs for similar instruments or prices from similar transactions and are classified as Level 2. Over-the-counter investments where significant unobservable inputs are used, such as financial pricing models, are classified as Level 3 investments.

Investments in private equity are valued using observable inputs, when available, and also include comparable market transactions, income and cost basis valuation techniques. The market approach includes using comparable market transactions or values. The income approach generally consists of the net present value of estimated future cash flows, adjusted as appropriate for liquidity, credit, market and/or other risk factors. Private equity investments are classified as Level 3 investments.

Investments in commingled funds are not publically traded, but the underlying assets held in these funds are traded in active markets and the prices for these assets are readily observable. Holdings in commingled funds are classified as Level 2 investments.

Investments in timber are valued primarily on valuations prepared by independent property appraisers. These appraisals are based on cash flow analysis, current market capitalization rates, recent comparable sales transactions, actual sales negotiations and bona fide purchase offers. Inputs include the species, age, volume and condition of timber stands growing on the land; the location, productivity, capacity and accessibility of the timber tracts; current and expected log prices; and current local prices for comparable investments. Timber investments are classified as Level 3 investments.

Hedge funds are based primarily on the net asset values and other financial information provided by management of the private investment funds. Hedge funds are classified as Level 2 if the plan is able to redeem the investment with the investee at net asset value as of the measurement date, or at a later date within a reasonable period of time. Hedge funds are classified as Level 3 if the investment cannot be redeemed at net asset value or it cannot be determined when the fund will be redeemed.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2010, we expect to make $120 million of contributions directly to pension plan assets and $1 million of discretionary contributions directly to the OPEB plan assets. The expected benefit payments for the pension benefit plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $158, $161, $167, $170, $178 and $961, respectively. The expected benefit payments for the OPEB plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $37, $40, $42, $45, $46 and $251, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from our assets. The benefit payment amounts reflect our net cost after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $4, $4, $5, $5, $6 and $40, respectively.

In 2010, PEC expects to make $85 million in contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $80, $81, $84, $84, $90 and $462, respectively. The expected benefit payments for the OPEB plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $17, $18, $20, $22, $23 and $133, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from PEC assets. The benefit payment amounts reflect the net cost to PEC after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $2, $2, $2, $3, $3 and $21, respectively.

In 2010, PEF expects to make $35 million in contributions directly to pension plan assets and expects to make $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $59, $60, $62, $64, $66 and $376, respectively. The expected benefit payments for the OPEB plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $18, $19, $19, $19, $20 and $98, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from PEF's assets. The benefit payment amounts reflect the net cost to PEF after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately \$2, \$2, \$2, \$2, \$3 and \$15, respectively.

B. FLORIDA PROGRESS ACQUISITION

During 2000, we completed our acquisition of Florida Progress. Florida Progress' pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of Florida Progress' nonbargaining unit benefit plans were merged with our benefit plans effective January 1, 2002.

PEF continues to recover qualified plan pension costs and OPEB costs in rates as if the acquisition had not occurred. The information presented in Note 16A is adjusted as appropriate to reflect PEF's rate treatment.

17. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

We are exposed to various risks related to changes in market conditions. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk if the counterparty fails to perform under the contract. We minimize such risk by performing credit and financial reviews using a combination of financial analysis and publicly available credit ratings of such counterparties. Potential nonperformance by counterparties is not expected to have a material effect on our financial position or results of operations.

A. COMMODITY DERIVATIVES

GENERAL

Most of our physical commodity contracts are not derivatives or qualify as normal purchases or sales. Therefore, such contracts are not recorded at fair value.

DISCONTINUED OPERATIONS

As discussed in Note 3C, in 2007 our subsidiary PVI sold or assigned substantially all of its CCO physical and commercial assets and liabilities representing substantially all of our nonregulated energy marketing and trading operations. For the year ended December 31, 2007, \$88 million of after-tax gains from derivative instruments related to our nonregulated energy marketing and trading operations was included in discontinued operations on the Consolidated Statements of Income.

In 2007, we entered into derivative contracts to hedge economically a portion of our synthetic fuels cash flow exposure to the risk of rising oil prices. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash in January 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo Synfuel LLC (Ceredo). As discussed in Note 3E, we disposed of our 100 percent ownership interest in Ceredo in March 2007. Progress Energy is the primary beneficiary of, and continues to consolidate, Ceredo in accordance with GAAP for variable interest entities, but we have recorded a 100 percent noncontrolling interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of \$168 million related to these contracts. Of this amount, \$57 million was attributable to Ceredo, of which \$42 million was attributed to noncontrolling interest for the portion of the gain subsequent to the disposal of Ceredo.

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions.

The Utilities have derivative instruments through 2015 related to their exposure to price fluctuations on fuel oil and natural gas purchases. The majority of our financial hedge agreements will settle in 2010 and 2011. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause.

Certain hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

Certain counterparties have held cash collateral from PEC in support of these instruments. PEC had a $7 million and an $18 million cash collateral asset included in prepayments and other current assets on the PEC Consolidated Balance Sheet at December 31, 2009 and 2008, respectively. At December 31, 2009, PEC had 50.3 million MMBtu notional of natural gas related to outstanding commodity derivative swaps that were entered into to hedge forecasted natural gas purchases. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted PEF's cash collateral asset included in derivative collateral posted on the PEF Balance Sheet, which was $139 million at December 31, 2009, compared to $335 million at December 31, 2008. At December 31, 2009, PEF had 182.4 million MMBtu notional of natural gas and 56.3 million gallons notional of oil related to outstanding commodity derivative swaps that were entered into to hedge forecasted oil and natural gas purchases.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges. From time to time we hedge exposure to market risk associated with fluctuations in the price of power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. At December 31, 2009, we had 0.4 million gallons notional of gasoline and 0.5 million gallons notional of heating oil related to outstanding commodity derivative swaps at each of PEC and PEF that were entered into to hedge forecasted gasoline and diesel purchases. Realized gains and losses are recorded net as part of fleet vehicle fuel costs. At December 31, 2009 and 2008, neither we nor the Utilities had material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities' results of operations for 2009, 2008 and 2007.

At December 31, 2009 and 2008, the amount recorded in our or the Utilities' accumulated other comprehensive income related to commodity cash flow hedges was not material.

B. INTEREST RATE DERIVATIVES – FAIR VALUE OR CASH FLOW HEDGES

We use cash flow hedging strategies to reduce exposure to changes in cash flow due to fluctuating interest rates. We use fair value hedging strategies to reduce exposure to changes in fair value due to interest rate changes. Our cash flow hedging strategies are primarily accomplished through the use of forward starting swaps and our fair value hedging strategies are primarily accomplished through the use of fixed-to-floating swaps. The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by the counterparty, the exposure in these transactions is the cost of replacing the agreements at current market rates.

CASH FLOW HEDGES

At December 31, 2009, all open forward starting swaps will reach their mandatory termination dates within three years. At December 31, 2009, including amounts related to terminated hedges, we had $35 million of after-tax losses, including $27 million of after-tax losses at PEC and $3 million of after-tax gains at PEF, recorded in accumulated other comprehensive income related to interest cash flow hedges. It is expected that in the next 12 months losses of $7 million and $4 million, net of tax, will be reclassified to interest expense at Progress Energy and PEC, respectively. The actual amounts that will be reclassified to earnings may vary from the expected amounts as a result of the timing of debt issuances at the Parent and the Utilities and changes in market value of currently open forward starting swaps.

At December 31, 2008, including amounts related to terminated hedges, we had $56 million of after-tax losses, including $35 million of after-tax losses at PEC recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2007, including amounts related to terminated hedges, we had $24 million of after-tax losses, including $12 million of after-tax losses at PEC and $8 million of after-tax losses at PEF, recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2009, Progress Energy had $325 million notional of open forward starting swaps, including $100 million at PEC and $75 million at PEF. At December 31, 2008, Progress Energy had $450 million notional of open forward starting swaps, including $250 million at PEC. At December 31, 2008, PEF had no open forward starting swaps. During January 2010, Progress Energy entered into $175 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances, including $75 million notional at PEF.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At December 31, 2009 and 2008, neither we nor the Utilities had any outstanding positions in such contracts.

C. CONTINGENT FEATURES

Certain of our derivative instruments contain provisions defining fair value thresholds requiring the posting of collateral for hedges in a liability position greater than such threshold amounts. The thresholds are tiered and based on the individual company's credit rating with each of the major credit rating agencies. Higher credit ratings have a higher threshold requiring a lower amount of the outstanding liability position to be covered by posted collateral. Conversely, lower credit ratings require a higher amount of the outstanding liability position to be covered by posted collateral. If our credit ratings were to be downgraded, we may have to post additional collateral on certain hedges in liability positions.

In addition, certain of our derivative instruments contain provisions that require our debt to maintain an investment grade credit rating from each of the major credit rating agencies. If our debt were to fall below investment grade, we would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions.

The aggregate fair value of all derivative instruments at Progress Energy with credit risk-related contingent features that were in a liability position at December 31, 2009, was $405 million, for which Progress Energy had posted collateral of $146 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2009, Progress Energy would have been required to post an additional $260 million of collateral with its counterparties.

The aggregate fair value of all derivative instruments at PEC with credit risk-related contingent features that were in a liability position at December 31, 2009, was $90 million, for which PEC had posted collateral of $7 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2009, PEC would have been required to post an additional $83 million of collateral with its counterparties.

The aggregate fair value of all derivative instruments at PEF with credit risk-related contingent features that were in a liability position at December 31, 2009, was $315 million, for which PEF had posted collateral of $139 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered on December 31, 2009, PEF would have been required to post an additional $177 million of collateral with its counterparties.

D. DERIVATIVE INSTRUMENT AND HEDGING ACTIVITY INFORMATION

Progress Energy

The following table presents the fair value of derivative instruments at December 31, 2009 and 2008:

Instrument / Balance sheet location	**December 31, 2009**		December 31, 2008	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		**$–**		$(2)
Interest rate derivatives				
Prepayments and other current assets	**$5**		$–	
Other assets and deferred debits	**14**		–	
Derivative liabilities, current				(65)
Total derivatives designated as hedging instruments	**19**	**–**	–	(67)
Derivatives not designated as hedging instruments				
Commodity derivatives(a)				
Prepayments and other current assets	**11**		9	
Other assets and deferred debits	**9**		1	
Derivative liabilities, current		**(189)**		(425)
Derivative liabilities, long-term		**(236)**		(263)
CVOs(b)				
Other liabilities and deferred credits		**(15)**		(34)
Fair value of derivatives not designated as hedging instruments	**20**	**(440)**	10	(722)
Fair value loss transition adjustment(c)				
Derivative liabilities, current		**(1)**		(1)
Derivative liabilities, long-term		**(4)**		(6)
Total derivatives not designated as hedging instruments	**20**	**(445)**	10	(729)
Total derivatives	**$39**	**$(445)**	$10	$(796)

(a) Substantially all of these contracts receive regulatory treatment.

(b) The Parent issued 98.6 million CVOs in connection with the acquisition of Florida Progress during 2000 (See Note 15).

(c) In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contract (See Note 20).

The following tables present the effect of derivative instruments on the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Income for the years ended December 31, 2009 and 2008:

Derivatives Designated as Hedging Instruments

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives(a) 2009	2008	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income(a)	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income(a) 2009	2008	Location of Gain or (Loss) Recognized in Income on Derivatives(b)	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives(b) 2009	2008
Commodity cash flow derivatives	**$1**	$(2)		**$–**	$–		**$–**	$–
Interest rate derivatives(c)	**15**	(35)	Interest charges	**(6)**	(3)	Interest charges	**(3)**	1

(a) Effective portion.
(b) Related to ineffective portion and amount excluded from effectiveness testing.
(c) Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

Derivatives Not Designated as Hedging Instruments

Instrument (in millions)	Realized Gain or (Loss)(a) 2009	2008	Unrealized Gain or (Loss)(b) 2009	2008
Commodity derivatives	**$(659)**	$174	**$(387)**	$(653)

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause and are reflected in fuel used in electric generation on the Consolidated Statements of Income.
(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

Instrument (in millions)	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives 2009	2008
Commodity derivatives	Other, net	**$1**	$(3)
Fair value loss transition adjustment	Other, net	**2**	3
CVOs	Other, net	**19**	–
Total		**$22**	$–

PEC

The following table presents the fair value of derivative instruments at December 31, 2009 and 2008:

Instrument / Balance sheet location	**December 31, 2009**		December 31, 2008	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		**$–**		$(1)
Interest rate derivatives				
Other assets and deferred debits	**$8**		$–	
Derivative liabilities, current		**–**		(35)
Total derivatives designated as hedging instruments	**8**	**–**	–	(36)
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Derivative liabilities, current		**(28)**		(45)
Other liabilities and deferred credits		**(62)**		(54)
Fair value of derivatives not designated as hedging instruments		**(90)**		(99)
Fair value loss transition adjustment[b]				
Derivative liabilities, current		**(1)**		(1)
Other liabilities and deferred credits		**(4)**		(6)
Total derivatives not designated as hedging instruments		**(95)**		(106)
Total derivatives	**$8**	**$(95)**	$–	$(142)

(a) Substantially all of these contracts receive regulatory treatment.

(b) In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contract (See Note 20).

The following tables present the effect of derivative instruments on the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Income for the years ended December 31, 2009 and 2008:

Derivatives Designated as Hedging Instruments

Instrument	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives(a)		Location of Gain or (Loss) Reclassified from Accumulated OCI into Income(a)	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income(a)		Location of Gain or (Loss) Recognized in Income on Derivatives(b)	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives(b)	
(in millions)	**2009**	2008		**2009**	2008		**2009**	2008
Commodity cash flow derivatives	**$–**	$(1)		**$–**	$–		**$–**	$–
Interest rate derivatives(c)	**5**	(25)	Interest charges	**(3)**	(1)	Interest charges	**(2)**	–

(a) Effective portion.
(b) Related to ineffective portion and amount excluded from effectiveness testing.
(c) Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

Derivatives Not Designated as Hedging Instruments

Instrument	Realized Gain or (Loss)(a)		Unrealized Gain or (Loss)(b)	
(in millions)	**2009**	2008	**2009**	2008
Commodity derivatives	**$(76)**	$2	**$(68)**	$(110)

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause and are reflected in fuel used in electric generation on the Consolidated Statements of Income.
(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

Instrument	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
(in millions)		**2009**	2008
Commodity derivatives	Other, net	**$1**	$(3)
Fair value loss transition adjustment	Other, net	**2**	3
Total		**$3**	$–

PEF

The following table presents the fair value of derivative instruments at December 31, 2009 and 2008:

Instrument / Balance sheet location	**December 31, 2009**		December 31, 2008	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Interest rate derivatives				
Prepayments and other current assets	**$5**		$–	
Total derivatives designated as hedging instruments	**5**		–	
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	**11**		9	
Other assets and deferred debits	**9**		1	
Derivative liabilities, current		**$(161)**		$(380)
Derivative liabilities, long-term		**(174)**		(209)
Total derivatives not designated as hedging instruments	**20**	**(335)**	10	(589)
Total derivatives	**$25**	**$(335)**	$10	$(589)

(a) Substantially all of these contracts receive regulatory treatment.

The following tables present the effect of derivative instruments on the Statements of Comprehensive Income and the Statements of Income for the years ended December 31, 2009 and 2008:

Derivatives Designated as Hedging Instruments

Instrument	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a]		Location of Gain or (Loss) Reclassified from Accumulated OCI into Income[a]	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a]		Location of Gain or (Loss) Recognized in Income on Derivatives[b]	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b]	
(in millions)	**2009**	2008		**2009**	2008		**2009**	2008
Commodity cash flow derivatives	**$1**	$(1)		**$–**	$–		**$–**	$–
Interest rate derivatives[c]	**3**	8	Interest charges	**–**	–	Interest charges	**–**	1

(a) Effective portion.

(b) Related to ineffective portion and amount excluded from effectiveness testing.

(c) Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

Derivatives Not Designated as Hedging Instruments

Instrument	Realized Gain or (Loss)(a)		Unrealized Gain or (Loss)(b)	
(in millions)	**2009**	2008	**2009**	2008
Commodity derivatives	**$(583)**	$172	**$(319)**	$(543)

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause and are reflected in fuel used in electric generation on the Statements of Income.

(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

18. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees may include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements, trading operations and cash management. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2009, the Parent had issued $391 million of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23). Subsequent to December 31, 2009, the Parent issued a $76 million guarantee for performance assurance of a wholly owned indirect subsidiary. We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheet.

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of the Public Utility Holding Company Act of 1935. The repeal of the Public Utility Holding Company Act of 1935 effective February 8, 2006, and subsequent regulation by the FERC did not change our current intercompany services. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, construction management and other centralized administrative, management and support services. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. Billings from affiliates are capitalized or expensed depending on the nature of the services rendered. Amounts receivable from and/or payable to affiliated companies for these services are included in receivables from affiliated companies and payables to affiliated companies on the Balance Sheets.

PESC provides the majority of the affiliated services under the approved agreements. Services provided by PESC during 2009, 2008 and 2007 to PEC amounted to $170 million, $194 million and $182 million, respectively, and services provided to PEF were $147 million, $160 million and $174 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2009, 2008 and 2007 amounted to $36 million, $44 million and $54 million, respectively. Services provided by PEF to PEC during 2009, 2008 and 2007 amounted to $12 million, $12 million and $10 million, respectively.

PEC and PEF participate in an internal money pool, operated by Progress Energy, to more effectively utilize cash resources and to reduce outside short-term borrowings. The money pool is also used to settle intercompany balances. The weighted-average interest rate for the money pool was 0.73%, 3.29% and 5.49% for the years ended December 31, 2009, 2008 and 2007, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Balance Sheets. PEC and PEF recorded insignificant interest expense related to the money pool for all the years presented.

PEC and its wholly owned subsidiaries and PEF have entered into the Tax Agreement with the Parent (See Note 14).

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

Our reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. These electric operations also distribute and sell electricity to other utilities, primarily on the east coast of the United States.

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative thresholds for disclosure as separate reportable business segments.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost.

In the following tables, capital and investment expenditures include property additions, acquisitions of nuclear fuel and other capital investments. Operational results and assets to be divested are not included in the table presented below.

(in millions)	**PEC**	**PEF**	**Corporate and Other**	**Eliminations**	**Totals**
At and for the year ended December 31, 2009					
Revenues					
Unaffiliated	**$4,627**	**$5,249**	**$9**	**$–**	**$9,885**
Intersegment	**–**	**2**	**234**	**(236)**	**–**
Total revenues	**4,627**	**5,251**	**243**	**(236)**	**9,885**
Depreciation, amortization and accretion	**470**	**502**	**14**	**–**	**986**
Interest income	**5**	**4**	**38**	**(33)**	**14**
Total interest charges, net	**195**	**231**	**286**	**(33)**	**679**
Income tax expense (benefit)[(a)]	**294**	**209**	**(87)**	**–**	**416**
Ongoing Earnings (loss)	**540**	**460**	**(154)**	**–**	**846**
Total assets	**13,502**	**13,100**	**20,538**	**(15,904)**	**31,236**
Capital and investment expenditures	**962**	**1,532**	**21**	**(12)**	**2,503**

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
At and for the year ended December 31, 2008					
Revenues					
Unaffiliated	$4,429	$4,730	$8	$ –	$9,167
Intersegment	–	1	361	(362)	–
Total revenues	4,429	4,731	369	(362)	9,167
Depreciation, amortization and accretion	518	306	15	–	839
Interest income	12	9	38	(35)	24
Total interest charges, net	207	208	259	(35)	639
Income tax expense (benefit)	298	181	(84)	–	395
Ongoing Earnings (loss)	531	383	(138)	–	776
Total assets	13,165	12,471	17,483	(13,246)	29,873
Capital and investment expenditures	939	1,601	33	(13)	2,560

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
At and for the year ended December 31, 2007					
Revenues					
Unaffiliated	$4,385	$4,748	$ 20	$ –	$9,153
Intersegment	–	1	393	(394)	–
Total revenues	4,385	4,749	413	(394)	9,153
Depreciation, amortization and accretion	519	366	20	–	905
Interest income	21	9	55	(51)	34
Total interest charges, net	210	173	258	(53)	588
Income tax expense (benefit)	295	144	(105)	–	334
Ongoing Earnings (loss)	498	315	(118)	–	695
Total assets	11,955	10,063	16,356	(12,088)	26,286
Capital and investment expenditures	941	1,262	3	(2)	2,204

(a) Income tax expense (benefit) for 2009 excludes tax impact of $17 million benefit at PEC and $1 million benefit at Corporate and Other for Ongoing Earnings adjustments.

Management uses the non-GAAP financial measure "Ongoing Earnings" as a performance measure to evaluate the results of our segments and operations. A reconciliation of consolidated Ongoing Earnings to net income attributable to controlling interests for the years ended 2009, 2008 and 2007, respectively, is as follows:

(in millions)	**2009**	2008	2007
Ongoing Earnings	**$846**	$776	$695
CVO mark-to-market	**19**	–	(2)
Impairment, net of tax benefit of $1	**(2)**	–	–
Plant retirement charge, net of tax benefit of $11	**(17)**	–	–
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax benefit of $6 (See Note 24)	**(10)**	–	–
Valuation allowance and related net operating loss carry forward	–	(3)	–
Continuing income attributable to noncontrolling interests, net of tax	**4**	5	9
Income from continuing operations	**840**	778	702
Discontinued operations, net of tax	**(79)**	58	(206)
Net income attributable to noncontrolling interests, net of tax	**(4)**	(6)	8
Net income attributable to controlling interests	**$757**	$830	$504

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income; AFUDC equity, which represents the estimated equity costs of capital funds necessary to finance the construction of new regulated assets; and other, net. The components of other, net as shown on the accompanying Statements of Income are presented below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities.

Progress Energy

(in millions)	**2009**	2008	2007
Nonregulated energy and delivery services income, net	**$17**	$17	$12
Fair value loss transition adjustment amortization (Note 17D)	**2**	3	4
CVO unrealized gain (loss), net (Note 15)	**19**	–	(2)
Donations	**(20)**	(25)	(22)
Other, net	**(12)**	(12)	1
Other, net	**$6**	$(17)	$(7)

PEC

(in millions)	**2009**	2008	2007
Nonregulated energy and delivery services income, net	**$6**	$11	$6
Fair value loss transition adjustment amortization (Note 17D)	**2**	3	4
Donations	**(10)**	(14)	(9)
Other, net	**(16)**	4	5
Other, net	**$(18)**	$4	$6

PEF

(in millions)	**2009**	2008	2007
Nonregulated energy and delivery services income, net	**$11**	$8	$8
Donations	**(10)**	(11)	(8)
Other, net	**4**	(7)	(2)
Other, net	**$5**	$(10)	$(2)

21. ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations. Environmental laws and regulations frequently change and the ultimate costs of compliance cannot always be precisely estimated.

A. HAZARDOUS AND SOLID WASTE

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the United States Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida, or potentially responsible party (PRP) groups as described below in greater detail. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted. A discussion of sites by legal entity follows.

We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. We measure our liability for these sites based on available evidence including our experience in investigating and remediating environmentally impaired sites. The process often involves assessing and developing cost-sharing arrangements with other PRPs. For all sites, as assessments are developed and analyzed, we will accrue costs for the sites to the extent our liability is probable and the costs can be reasonably estimated. Because the extent of environmental impact, allocation among PRPs for all sites, remediation alternatives (which could involve either minimal or significant efforts), and concurrence of the regulatory authorities have not yet reached the stage where a reasonable estimate of the remediation costs can be made, we cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is probable that current estimates will change and additional losses, which could be material, may be incurred in the future.

The following table contains information about accruals for environmental remediation expenses described below. Accruals for probable and estimable costs related to various environmental sites, which were included in other current liabilities and other liabilities and deferred credits on the Balance Sheets, at December 31 were:

(in millions)	**2009**	2008
PEC		
MGP and other sites[(a)]	**$13**	$16
PEF		
Remediation of distribution and substation transformers	**20**	22
MGP and other sites	**9**	15
Total PEF environmental remediation accruals[(b)]	**29**	37
Total Progress Energy environmental remediation accruals	**$42**	$53

(a) Expected to be paid out over one to five years.
(b) Expected to be paid out over one to 15 years.

PROGRESS ENERGY

Including PEC's Ward Transformer site located in Raleigh, N.C. (Ward), PEF's distribution and substation transformers sites, and the Utilities' MGP sites discussed below, for the year ended December 31, 2009, we accrued approximately $16 million and spent approximately $27 million. For the year ended December 31, 2008, we accrued approximately $25 million and spent approximately $36 million. For the year ended December 31, 2007, we accrued approximately $8 million and spent approximately $27 million.

In addition to these sites, we incurred indemnity obligations related to certain pre-closing liabilities of divested subsidiaries, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC has recorded a minimum estimated total remediation cost for all of its remaining MGP sites based upon its historical experience with remediation of several of its MGP sites. The accruals for PEF's MGP and other sites relate to two former MGP sites and other sites associated with PEF that have required, or are anticipated to require, investigation and/or remediation. The maximum amount of the range for all the sites cannot be determined at this time. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

In 2004, the EPA advised PEC that it had been identified as a PRP at the Ward site. The EPA offered PEC and a number of other PRPs the opportunity to negotiate the removal action for the Ward site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the Ward site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the Ward site. At December 31, 2009 and 2008, PEC's recorded liability for the site was approximately $4 million and $7 million, respectively. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. On September 12, 2008, PEC filed an initial civil action against a number of PRPs seeking contribution for and recovery of costs incurred in remediating the Ward site, as well as a declaratory judgment that defendants are jointly and severally liable for response costs at the site. On March 13, 2009, a subsequent action was filed against additional PRPs, and on April 30, 2009, suit was filed against the remaining approximately 160 PRPs. PEC has settled with a number of the PRPs and is in active settlement negotiations with others. With respect to the defendants that do not settle, the federal district court in which this matter is pending requires that alternative dispute resolution be pursued early in civil litigation but it is unclear what process the court will require. The outcome of these matters cannot be predicted.

On September 30, 2008, the EPA issued a Record of Decision for the operable unit for stream segments downstream from the Ward site (Ward OU1) and advised 61 parties, including PEC, of their identification as PRPs for Ward OU1 and for the operable unit for further investigation at the Ward facility and certain adjacent areas (Ward OU2). The EPA's estimate for the selected remedy for Ward OU1 is approximately $6 million. The EPA offered PEC and the other PRPs the opportunity to negotiate implementation of a response action for Ward OU1 and a remedial investigation and feasibility study for Ward OU2, as well as reimbursement to the EPA of approximately $1 million for the EPA's past expenditures in addressing conditions at the site. On January 19, 2009, PEC and several of the other participating PRPs at the Ward site submitted a letter containing a good faith response to the EPA's special notice letter. Another group of PRPs separately submitted a good faith response, which the EPA advised would be used to negotiate implementation of the required actions. The other PRPs' good faith response was subsequently withdrawn. Discussions among representatives of certain PRPs, including PEC, and the EPA are ongoing. Although a loss is considered probable, an agreement among the PRPs for these matters has not been reached; consequently, it is not possible at this time to reasonably estimate the total amount of PEC's obligation, if any, for Ward OU1 and Ward OU2.

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF has reviewed all distribution transformer sites and all substation sites for mineral oil-impacted soil caused by equipment integrity issues. Should further distribution transformer sites be identified outside of this population, the distribution O&M costs will not be recoverable through the ECRC. For the year ended December 31, 2009, PEF accrued approximately $13 million due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $15 million related to the remediation of transformers. For the year ended December 31, 2008, PEF accrued approximately $17 million, due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $26 million related to the remediation of transformers. For the year ended December 31, 2007, PEF accrued approximately $10 million due to an increase in estimated remediation costs and spent approximately $22 million related to the remediation of transformers. At December 31, 2009 and 2008, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

PEC

Including Ward, and MGP sites previously discussed in "Progress Energy," for the year ended December 31, 2009, PEC accrued approximately $3 million and spent approximately $6 million. For the year ended December 31, 2008, PEC accrued and spent approximately $8 million. For the year ended December 31, 2007, PEC's accruals and expenditures were not material. These amounts primarily relate to the Ward site, which is discussed under "Progress Energy" above.

PEF

Including the distribution and substation transformer sites and MGP and other sites previously discussed in "Progress Energy," for the year ended December 31, 2009, PEF accrued approximately $13 million and spent approximately $21 million, including $6 million of expenditures related to MGP and other sites. For the year ended December 31, 2008, PEF accrued approximately $17 million and spent approximately $28 million, which primarily related to distribution and substation transformer sites. For the year ended December 31, 2007, PEF accrued approximately $10 million and spent approximately $22 million, which primarily related to distribution and substation transformer sites. For the years ended December 31, 2008 and 2007, PEF's accruals and expenditures for MGP and other sites were not material.

B. AIR AND WATER QUALITY

At December 31, 2009 and 2008, we were subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations included the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the Clean Smokestacks Act, enacted in June 2002 and mercury regulation. PEC's and PEF's environmental compliance capital expenditures related to these regulations began in 2002 and 2005, respectively. At December 31, 2009, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $2.119 billion, including $1.054 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and $1.065 billion at PEF, which related entirely to in-process CAIR projects. At December 31, 2008, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.859 billion, including $1.012 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and $847 million at PEF, which related entirely to in-process CAIR projects.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, which vacated the CAIR in its entirety. On December 23, 2008, in response to petitions for rehearing filed by a number of parties, the D.C. Court of Appeals remanded the CAIR without vacating the rule for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. The outcome of the EPA's further proceedings cannot be predicted. Because the D.C. Court of Appeals December 23, 2008 decision remanded the CAIR, the current implementation of the CAIR continues to fulfill best available retrofit technology (BART) for SO_2 and NOx for BART-affected units under the CAVR. Should this determination change as the CAIR is revised, CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions or BART-eligible units.

On February 8, 2008, the D.C. Court of Appeals vacated the delisting determination and the Clean Air Mercury Rule (CAMR). The U.S. Supreme Court declined to hear an appeal of the D.C. Court of Appeals' decision in January 2009. As a result, the EPA subsequently announced that it will develop a maximum achievable control technology (MACT) standard consistent with the agency's original listing determination. The three states in which the Utilities operate adopted mercury regulations implementing CAMR and submitted their state implementation rules to the EPA. It is uncertain how the decision that vacated the federal CAMR will affect the state rules; however, state-specific provisions are likely to remain in effect. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. We are currently evaluating the impact of these decisions. The outcome of these matters cannot be predicted.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at CR5 and CR4. The CR5 project was placed in service on December 2, 2009, and the CR4 project is expected to be placed in service in 2010. Under an agreement with the FDEP, PEF will retire CR1 and CR2 as coal-fired units and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was anticipated to be around 2020. As discussed under "Other Matters – Nuclear," PEF expects the schedule for the commercial operation of Levy to shift later than the 2016 to 2018 timeframe by a minimum of 20 months. PEF is required to advise the FDEP of any developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated completion date of the first fuel cycle for Levy Unit 2. PEF has advised the FDEP of a Levy schedule shift. We are currently evaluating the impacts of the Levy schedule. We cannot predict the outcome of this matter.

We account for emission allowances as inventory using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. The EPA is continuing to record allowance allocations under the CAIR NOx trading program, in some cases for years beyond the estimated two-year period for promulgation of a replacement rule. The EPA's continued recording of CAIR NOx allowance allocations does not guarantee that allowances will continue to be usable for compliance after a replacement rule is finalized or that they will continue to have value in the future. SO_2 emission allowances will be utilized to comply with existing Clean Air Act requirements. PEF's CAIR expenses, including NOx allowance inventory expense, are recoverable through the ECRC. At December 31, 2009 and 2008, PEC had approximately $13 million and $22 million, respectively, in SO_2 emission allowances and an immaterial amount of NOx emission allowances. At December 31, 2009 and 2008, PEF had approximately $7 million and $11 million, respectively, in SO_2 emission allowances and approximately $36 million and $65 million, respectively, in NOx emission allowances.

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. Two of PEC's largest coal-fired generating units (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. Pursuant to joint ownership agreements, the joint owners are required to pay a portion of the costs of owning and operating these plants. PEC has determined that the most cost-effective Clean Smokestacks Act compliance strategy is to maximize the SO_2 removal from its larger coal-fired units, including Roxboro No. 4 and Mayo, so as to avoid the installation of expensive emission controls on its smaller coal-fired units. In order to address the joint owner's concerns that such a compliance strategy would result in a disproportionate share of the cost of compliance for the jointly owned units, in 2005 PEC entered into an agreement with the joint owner to limit its aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately $38 million. PEC recorded a related liability for the joint owner's share of estimated costs in excess of the contract amount. All of PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, including projects at the Mayo and Roxboro Plants, have been placed in service and PEC estimates its remaining exposure is not material. See Note 22C for further discussion of PEC's indemnification liability. Because PEC has taken a system-wide compliance approach, its North Carolina retail ratepayers have significantly benefited from the strategy of focusing emission reduction efforts on the jointly owned units, and, therefore, PEC believes that any costs in excess of the joint owner's share should be recovered from North Carolina retail ratepayers, consistent with other capital expenditures associated with PEC's compliance with the Clean Smokestacks Act. On September 5, 2008, the NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million, including eligible compliance costs in excess of the joint owner's share, as the projects are closed to plant in service.

22. COMMITMENTS AND CONTINGENCIES

A. PURCHASE OBLIGATIONS

In most cases, our purchase obligation contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. At December 31, 2009, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2010	2011	2012	2013	2014	Thereafter
Fuel	$2,647	$2,335	$1,953	$1,706	$1,405	$8,217
Purchased power	445	467	447	445	367	3,636
Construction obligations	1,820	1,725	1,453	1,524	1,313	1,543
Other purchase obligations	52	74	36	27	19	163
Total	$4,964	$4,601	$3,889	$3,702	$3,104	$13,559

PEC

(in millions)	2010	2011	2012	2013	2014	Thereafter
Fuel	$1,354	$1,192	$1,004	$1,003	$802	$3,553
Purchased power	91	98	80	73	68	505
Construction obligations	365	184	13	15	4	–
Other purchase obligations	16	11	5	5	6	6
Total	$1,826	$1,485	$1,102	$1,096	$880	$4,064

PEF

(in millions)	2010	2011	2012	2013	2014	Thereafter
Fuel	$1,293	$1,143	$949	$703	$603	$4,664
Purchased power	354	369	367	372	299	3,131
Construction obligations	1,455	1,541	1,440	1,509	1,309	1,543
Other purchase obligations	23	36	29	21	14	157
Total	$3,125	$3,089	$2,785	$2,605	$2,225	$9,495

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel as well as transportation agreements for the related fuel. Our payments under these commitments were $2.921 billion, $3.078 billion and $2.360 billion for 2009, 2008 and 2007, respectively. PEC's total payments under these commitments for its generating plants were $1.527 billion, $1.446 billion and $1.049 billion in 2009, 2008 and 2007, respectively. PEF's payments totaled $1.394 billion, $1.632 billion and $1.311 billion in 2009, 2008 and 2007, respectively. Essentially all fuel and certain purchased power costs incurred by PEC and PEF are recovered through their respective cost-recovery clauses.

In December 2008, PEF entered into a nuclear fuel fabrication contract for the planned Levy nuclear units. (See discussion under Construction Obligations below.) This $334 million contract (fuel plus related core components) is for the period from 2014 through 2027 and contains exit provisions with termination fees that vary based on the circumstance.

Both PEC and PEF have ongoing purchased power contracts with certain co-generators (primarily QFs) with expiration dates ranging from 2010 to 2029. These purchased power contracts generally provide for capacity and energy payments.

PEC executed two long-term tolling agreements for the purchase of all of the power generated from Broad River LLC's Broad River facility. One agreement provides for the purchase of approximately 500 MW of capacity through May 2021 with average minimum annual payments of approximately $24 million, primarily representing capital-related capacity costs. The second agreement provides for the additional purchase of approximately 335 MW of capacity through February 2022 with average annual payments of approximately $24 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River LLC's Broad River facility agreements amounted to $46 million, $44 million and $39 million in 2009, 2008 and 2007, respectively.

In 2007, PEC executed long-term agreements for the purchase of power from Southern Power Company. The agreements provide for capacity purchases of 305 MW (68 percent of net output) for 2010, 310 MW (30 percent of net output) for 2011 and 150 MW (33 percent of net output) annually thereafter through 2019. Estimated payments for capacity under the agreements are $23 million for 2010, $24 million for 2011 and $12 million annually thereafter through 2019.

PEC has various pay-for-performance contracts with QFs, including renewable energy, for approximately 200 MW of firm capacity expiring at various times through 2029. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $24 million, $55 million and $95 million in 2009, 2008 and 2007, respectively.

PEF has firm contracts for approximately 489 MW of purchased power with other utilities, including a contract with Southern Company for approximately 414 MW (12 percent of net output) of purchased power that ends in 2010. Additional contracts with Southern Company for approximately 424 MW (25 percent of net output) of purchased power annually start in 2010 and extend through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $149 million, $178 million and $161 million for 2009, 2008 and 2007, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $60 million, $56 million, $44 million, $52 million and $52 million for 2010 through 2014, respectively, and $74 million payable thereafter.

PEF has ongoing purchased power contracts with certain QFs for 682 MW of firm capacity with expiration dates ranging from 2010 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. All ongoing commitments have been approved by the FPSC. Total capacity and energy payments made under these contracts amounted to $435 million, $440 million and $447 million for 2009, 2008 and 2007, respectively. Minimum expected future capacity payments under these contracts are $286 million, $301 million, $313 million, $310 million and $237 million for 2010 through 2014, respectively, and $3.042 billion payable thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

In 2009, PEC executed a long-term coal transportation agreement by combining, amending and restating previous agreements with Norfolk Southern Railroad, This agreement will support PEC's coal supply needs through June 2020. Expected future transportation payments under this agreement are $254 million, $264 million, $260 million, $254 million and $277 million for 2010 through 2014, respectively, with approximately $1.679 billion payable thereafter. Coal transportation expenses under these agreements were approximately $283 million in 2009. PEC's state utility commissions allow fuel-related costs to be recovered through fuel cost-recovery clauses.

PEC has entered into conditional agreements for firm pipeline transportation capacity to support PEC's gas supply needs for the period from April 2011 through August 2032. The estimated total cost to PEC associated with these agreements is approximately $1.598 billion, of which approximately $404 million will be classified as a capital lease. Due to the conditions of the capital lease agreement, the capital lease will not be recorded on PEC's balance sheet until approximately 2012. The transactions are subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related interstate and intrastate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in PEC's fuel commitments.

In April 2008 (and as amended in February 2009), PEF entered into conditional contracts and extensions of existing contracts with Florida Gas Transmission Company, LLC (FGT) for firm pipeline transportation capacity to support PEF's gas supply needs for the period from April 2011 through March 2036. The total cost to PEF associated with these agreements is estimated to be approximately $1.065 billion. In addition to the FGT contracts, PEF has entered into additional gas supply and transportation arrangements for the period from 2010 through 2036. The total current notional cost of these additional agreements is estimated to be approximately $1.043 billion. The FGT contracts along with the additional gas supply and transportation arrangements are subject to several conditions precedent, including various federal regulatory approvals, the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in PEF's fuel commitments.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $818 million, $1.018 billion and $698 million for 2009, 2008 and 2007, respectively. The majority of our construction obligations relate to PEF as discussed below.

PEC has purchase obligations related to various capital projects including new generation and transmission obligations. Total payments under PEC's construction-related contracts were $199 million, $140 million and $208 million for 2009, 2008 and 2007, respectively.

The majority of PEF's construction obligations relate to an engineering, procurement and construction (EPC) agreement that PEF entered into in December 2008 with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two approximately 1,100-MW Westinghouse AP1000 nuclear units planned for construction at Levy. Estimated payments and associated escalation totaling $8.608 billion are included for the multi-year contract and do not assume any joint ownership. The contractual obligations presented are in accordance with the existing terms of the EPC agreement. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. In 2009, the NRC indicated it would process PEF's limited work authorization request following COL issuance resulting in a minimum 20-month in-service schedule shift for the Levy units from the original 2016 to 2018 timeframe. Additional schedule shifts are likely given, among other things, the permitting and licensing process, state of Florida and macro-economic conditions and recent FPSC DSM and energy-efficiency goals and other decisions. Uncertainty regarding access to capital on reasonable terms could be another factor to affect the Levy schedule. In light of the regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Because of anticipated schedule shifts, we are negotiating an amendment to the Levy EPC agreement. We cannot currently predict the impact such amendment might have on the amount and timing of PEF's contractual obligations. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstance. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time and, accordingly, are not reflected in construction obligations. See Note 7C for additional information about the Levy project. PEF made payments of $243 million and $117 million in 2009 and 2008, respectively, toward long-lead equipment and engineering related to the EPC agreement. Additionally, PEF has other construction obligations related to various capital projects including new generation, transmission and environmental compliance. Total payments under PEF's other construction-related contracts were $376 million, $761 million and $490 million for 2009, 2008 and 2007, respectively.

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and PEF service agreements related to the Hines Energy Complex and the Bartow Plant. Our payments under these agreements were $56 million, $110 million and $75 million for 2009, 2008 and 2007, respectively.

PEC has various purchase obligations including obligations for limestone supply and fleet vehicles. Total purchases under these contracts were $14 million, $18 million and $6 million for 2009, 2008 and 2007, respectively.

Among PEF's other purchase obligations, PEF has long-term service agreements for the Hines Energy Complex and the Bartow Plant, emission obligations and fleet vehicles. Total payments under these contracts were $22 million, $58 million and $24 million for 2009, 2008 and 2007, respectively. Future obligations are primarily comprised of the long-term service agreements.

B. LEASES

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Our rent expense under operating leases totaled $37 million, $38 million and $40 million for 2009, 2008 and 2007, respectively. Our purchased power expense under agreements classified as operating leases was approximately $11 million, $152 million and $69 million in 2009, 2008 and 2007, respectively.

PEC's rent expense under operating leases totaled $26 million, $26 million and $23 million during 2009, 2008 and 2007, respectively. These amounts include rent expense allocated from PESC to PEC of $5 million, $5 million and $6 million for 2009, 2008 and 2007, respectively. Purchased power expense under agreements classified as operating leases was approximately $11 million, $9 million and $10 million in 2009, 2008 and 2007, respectively.

PEF's rent expense under operating leases totaled $11 million, $11 million and $15 million during 2009, 2008 and 2007, respectively. These amounts include rent expense allocated from PESC to PEF of $3 million, $3 million and $6 million for 2009, 2008 and 2007, respectively. Purchased power expense under agreements classified as operating leases was approximately $142 million and $59 million in 2008 and 2007, respectively. PEF had no purchased power expense under operating lease agreements for 2009.

Assets recorded under capital leases, including plant related to purchased power agreements, at December 31 consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Buildings	**$267**	$267	**$30**	$30	**$237**	$237
Less: Accumulated amortization	**(37)**	(28)	**(15)**	(14)	**(22)**	(14)
Total	**$230**	$239	**$15**	$16	**$215**	$223

Consistent with the ratemaking treatment for capital leases, capital lease expenses are charged to the same accounts that would be used if the leases were operating leases. Thus, our and the Utilities' capital lease expense is generally included in O&M or purchased power expense. Our capital lease expense totaled $26 million each for 2009 and 2008 and $22 million for 2007, which was primarily comprised of PEF's capital lease expense of $24 million each for 2009 and 2008 and $20 million for 2007.

At December 31, 2009, minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable operating and capital leases were:

	Progress Energy		PEC		PEF	
(in millions)	Capital	Operating	Capital	Operating	Capital	Operating
2010	$28	$35	$2	$25	$26	$6
2011	28	29	2	21	26	6
2012	28	48	2	20	26	26
2013	36	78	10	42	26	34
2014	26	77	–	42	26	33
Thereafter	246	941	–	558	246	382
Minimum annual payments	392	$1,208	16	$708	376	$487
Less amount representing imputed interest	(162)		(2)		(160)	
Present value of net minimum lease payments under capital leases	$230		$14		$216	

In 2003, we entered into an operating lease for a building for which minimum annual rental payments are approximately $7 million. The lease term expires July 2035 and provides for no rental payments during the last 15 years of the lease, during which period $53 million of rental expense will be recorded in the Consolidated Statements of Income.

In 2008, PEC entered into a 336-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for an initial minimum payment of approximately $18 million in 2013, with minimum annual payments escalating at a rate of 2.5 percent through 2032, for a total of approximately $460 million.

In 2009, PEC entered into a 240-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $10 million from July 2012 through September 2017, for a total of approximately $52 million.

In 2007, PEF entered into a 632-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $28 million from June 2012 through May 2027, for a total of approximately $420 million.

In 2005, PEF entered into an agreement for a capital lease for a building completed during 2006. The lease term expires March 2047 and provides for minimum annual payments of approximately $5 million from 2007 through 2026, for a total of approximately $103 million. The lease term provides for no payments during the last 20 years of the lease, during which period approximately $51 million of rental expense will be recorded in the Statements of Income.

In 2006, PEF extended the terms of a 517-MW (100 percent of net output) tolling agreement for purchased power, which is classified as a capital lease of the related plant, for an additional 10 years. The agreement calls for minimum annual payments of approximately $21 million from April 2007 through April 2024, for a total of approximately $348 million.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $11 million for 2010 and none thereafter. PEC's rents received are contingent upon usage and totaled $34 million for 2009 and $33 million each for 2008 and 2007. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $84 million, $81 million and $78 million for 2009, 2008 and 2007, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2010 and thereafter.

C. GUARANTEES

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2009, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Consolidated Balance Sheets.

At December 31, 2009, we have issued guarantees and indemnifications of and for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses. At December 31, 2009, our estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $458 million, including $32 million at PEF. Related to the sales of businesses, the latest specified notice period extends until 2013 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. At December 31, 2009 and 2008, we had recorded liabilities related to guarantees and indemnifications to third parties of approximately $34 million and $61 million, respectively. These amounts included $10 million for PEC at December 31, 2008, and $7 million and $8 million, respectively, for PEF at December 31, 2009 and 2008. During the year ended December 31, 2009, our indemnification liability for certain legal matters made in connection with the sale of businesses decreased by approximately $16 million as a result of a legal verdict discussed under "Synthetic Fuels Matters" in Note 22D. In 2005, PEC entered into an agreement with the joint owner of certain facilities at the Mayo and Roxboro Plants to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification. At December 31, 2009, all of PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, including projects at the Mayo and Roxboro Plants, had been placed in service. PEC estimates its remaining exposure under the indemnification is not material (See Note 21B). During the year ended December 31, 2009, PEC accrued approximately $2 million and spent approximately $12 million that exceeded the joint owner limit. During the year ended December 31, 2008, PEC made no additional accruals and spent approximately $20 million that exceeded the joint owner limit. As current estimates change, it is possible that additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

In addition, the Parent has issued $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23).

D. OTHER COMMITMENTS AND CONTINGENCIES

SPENT NUCLEAR FUEL MATTERS

Pursuant to the Nuclear Waste Policy Act of 1982, the Utilities entered into contracts with the DOE under which the DOE agreed to begin taking spent nuclear fuel by no later than January 31, 1998. All similarly situated utilities were required to sign the same standard contract.

The DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, the Utilities filed a complaint in the United States Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from our various facilities on or before January 31, 1998. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims. The Utilities have asserted nearly $91 million in damages incurred between January 31, 1998, and December 31, 2005; the time period set by the court for damages in this case. The Utilities will be free to file subsequent damage claims as they incur additional costs.

A trial was held in November 2007, and closing arguments were presented on April 4, 2008. On May 19, 2008, the Utilities received a ruling from the United States Court of Federal Claims awarding $83 million in the claim against the DOE for failure to abide by a contract for federal disposition of spent nuclear fuel. The United States Department of Justice requested that the Trial Court reconsider its ruling. The Trial Court did reconsider its ruling and reduced the damage award by an immaterial amount. On August 15, 2008, the Department of Justice appealed the United States Court of Federal Claims ruling to the D.C. Court of Appeals. Oral arguments were held on May 4, 2009. On July 21, 2009, the D.C. Court of Appeals vacated and remanded the calculation of damages back to the Trial Court but affirmed the portion of damages awarded that were directed to overhead costs and other indirect expenses. The Department of Justice requested a rehearing en banc but the D.C. Court of Appeals denied the motion on November 3, 2009. In the event that the Utilities recover damages in this matter, such recovery is not expected to have a material impact on the Utilities' results of operations given the anticipated regulatory and accounting treatment. However, the Utilities cannot predict the outcome of this matter.

SYNTHETIC FUELS MATTERS

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates arising out of an Asset Purchase Agreement dated as of October 19, 1999, and amended as of August 23, 2000, (the Asset Purchase Agreement) by and among U.S. Global, LLC (Global); Earthco; certain affiliates of Earthco; EFC Synfuel LLC (which was owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to the Asset Purchase Agreement. In a case filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case), Global had requested an unspecified amount of compensatory damages, as well as declaratory relief. Global asserted (1) that pursuant to the Asset Purchase Agreement, it was entitled to an interest in two synthetic fuels facilities previously owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it was entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities. As a result of the expiration of the Section 29 tax credit program on December 31, 2007, all of our synthetic fuels businesses were abandoned and we reclassified our synthetic fuels businesses as discontinued operations (See Note 3A).

The jury awarded Global $78 million. On October 23, 2009, Global filed a motion to assess prejudgment interest on the award. On November 20, 2009, the court granted the motion and assessed $55 million in prejudgment interest and entered judgment in favor of Global in a total amount of $133 million. During the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations (See Note 3A), which was net of a previously recorded indemnification liability of $16 million. In December 2009, we made a $154 million payment, which represents payment of the total judgment and a required premium equivalent to two years of interest, to the Broward County Clerk of Court bond account. On December 16, 2009, we filed notice of appeal. We cannot predict the outcome of this matter.

In a second suit filed in the Superior Court for Wake County, N.C., *Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC* (the North Carolina Global Case), the Progress Affiliates seek declaratory relief consistent with our interpretation of the Asset Purchase Agreement. Global was served with the North Carolina Global Case on April 17, 2003.

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss, but stayed the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress Affiliates appealed the superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal. Based upon the resolution of the Florida Global Case, we anticipate dismissal of the North Carolina Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the Florida Global Case related to amounts due to Global that were placed in escrow pursuant to a defined tax event. Upon the successful resolution of the IRS audit of the Earthco synthetic fuels facilities in 2006, and pursuant to a settlement agreement, the escrow totaling $42 million as of December 31, 2006, was paid to Global in January 2007.

NOTICE OF VIOLATION

On April 29, 2009, the EPA issued a notice of violation and opportunity to show cause with respect to a 16,000-gallon oil spill at one of PEC's substations in 2007. The notice of violation did not include specified sanctions sought. Subsequently, the EPA notified PEC that the agency is seeking monetary sanctions that are *de minimus* to our and PEC's results of operations or financial condition. Discussions between PEC and the EPA are ongoing. We cannot predict the outcome of this matter.

FLORIDA NUCLEAR COST RECOVERY

On February 8, 2010, a lawsuit was filed against PEF in state circuit court in Sumter County, Fla., alleging that the Florida nuclear cost-recovery statute (Section 366.93, Florida Statutes) violates the Florida Constitution, and seeking a refund of all monies collected by PEF pursuant to that statute with interest. The complaint also requests that the court grant class action status to the plaintiffs. PEF believes the lawsuit is without merit and will defend against it. We cannot predict the outcome of this matter.

OTHER LITIGATION MATTERS

We and our subsidiaries are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, we have made accruals and disclosures to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

23. CONDENSED CONSOLIDATING STATEMENTS

Presented below are the Condensed Consolidating Statements of Income, Balance Sheets and Cash Flows as required by Rule 3-10 of Regulation S-X. In September 2005, we issued our guarantee of certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.). Our guarantees are in addition to the previously issued guarantees of our wholly owned subsidiary, Florida Progress.

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing $300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities) and using the proceeds thereof to purchase from Funding Corp. $300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039 (Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes Guarantee (as discussed below). Funding Corp. is a wholly owned subsidiary of Florida Progress and was formed for the sole purpose of providing financing to Florida Progress and its subsidiaries. Funding Corp. does not engage in business activities other than such financing and has no independent operations. Since 1999, Florida Progress has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, Florida Progress guaranteed the payment of all distributions related to the $300 million Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (the Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by Florida Progress of the Trust's obligations under the Preferred Securities. The Preferred Securities and Preferred Securities Guarantee are listed on the New York Stock Exchange.

The Subordinated Notes may be redeemed at the option of Funding Corp. at par value plus accrued interest through the redemption date. The proceeds of any redemption of the Subordinated Notes will be used by the Trust to redeem proportional amounts of the Preferred Securities and common securities in accordance with their terms. Upon liquidation or dissolution of Funding Corp., holders of the Preferred Securities would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment. The annual interest expense is $21 million and is reflected in the Consolidated Statements of Income.

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. At December 31, 2009, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 11B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a variable-interest entity of which we are not the primary beneficiary. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In these condensed consolidating statements, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the consolidated financial results of Florida Progress only, which is primarily comprised of its wholly owned subsidiary PEF. The Non-guarantor Subsidiaries column includes the consolidated financial results of all non-guarantor subsidiaries, which is primarily comprised of our wholly owned subsidiary PEC. The Other column includes elimination entries for all intercompany transactions and other consolidation adjustments. Financial statements for PEC and PEF are separately presented elsewhere in this Form 10-K. All applicable corporate expenses have been allocated appropriately among the guarantor and non-guarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other non-guarantor subsidiaries operated as independent entities.

Condensed Consolidating Statement of Income
Year Ended December 31, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$5,259	$4,626	$–	$9,885
Affiliate revenues	–	–	235	(235)	–
Total operating revenues	–	5,259	4,861	(235)	9,885
Operating expenses					
Fuel used in electric generation	–	2,072	1,680	–	3,752
Purchased power	–	682	229	–	911
Operation and maintenance	8	839	1,269	(222)	1,894
Depreciation, amortization and accretion	–	502	484	–	986
Taxes other than on income	–	347	216	(6)	557
Other	–	13	–	–	13
Total operating expenses	8	4,455	3,878	(228)	8,113
Operating (loss) income	(8)	804	983	(7)	1,772
Other income (expense)					
Interest income	10	5	9	(10)	14
Allowance for equity funds used during construction	–	91	33	–	124
Other, net	18	6	(22)	4	6
Total other income (expense), net	28	102	20	(6)	144
Interest charges					
Interest charges	233	280	215	(10)	718
Allowance for borrowed funds used during construction	–	(27)	(12)	–	(39)
Total interest charges, net	233	253	203	(10)	679
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(213)	653	800	(3)	1,237
Income tax (benefit) expense	(93)	200	286	4	397
Equity in earnings of consolidated subsidiaries	875	–	–	(875)	–
Income (loss) from continuing operations	755	453	514	(882)	840
Discontinued operations, net of tax	2	(43)	(38)	–	(79)
Net income (loss)	757	410	476	(882)	761
Net (income) loss attributable to noncontrolling interests, net of tax	–	(3)	2	(3)	(4)
Net income (loss) attributable to controlling interests	$757	$407	$478	$(885)	$757

Condensed Consolidating Statement of Income
Year Ended December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$4,738	$4,429	$–	$9,167
Affiliate revenues	–	–	361	(361)	–
Total operating revenues	–	4,738	4,790	(361)	9,167
Operating expenses					
Fuel used in electric generation	–	1,675	1,346	–	3,021
Purchased power	–	953	346	–	1,299
Operation and maintenance	3	813	1,346	(342)	1,820
Depreciation, amortization and accretion	–	306	533	–	839
Taxes other than on income	–	309	207	(8)	508
Other	–	1	(4)	–	(3)
Total operating expenses	3	4,057	3,774	(350)	7,484
Operating (loss) income	(3)	681	1,016	(11)	1,683
Other income (expense)					
Interest income	11	9	16	(12)	24
Allowance for equity funds used during construction	–	95	27	–	122
Other, net	–	(18)	(4)	5	(17)
Total other income (expense), net	11	86	39	(7)	129
Interest charges					
Interest charges	201	263	227	(12)	679
Allowance for borrowed funds used during construction	–	(28)	(12)	–	(40)
Total interest charges, net	201	235	215	(12)	639
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(193)	532	840	(6)	1,173
Income tax (benefit) expense	(85)	172	306	2	395
Equity in earnings of consolidated subsidiaries	941	–	–	(941)	–
Income (loss) from continuing operations	833	360	534	(949)	778
Discontinued operations, net of tax	(3)	61	–	–	58
Net income (loss)	830	421	534	(949)	836
Net income attributable to noncontrolling interests, net of tax	–	(6)	–	–	(6)
Net income (loss) attributable to controlling interests	$830	$415	$534	$(949)	$830

Condensed Consolidating Statement of Income
Year Ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$4,768	$4,385	$–	$9,153
Affiliate revenues	–	–	391	(391)	–
Total operating revenues	–	4,768	4,776	(391)	9,153
Operating expenses					
Fuel used in electric generation	–	1,764	1,381	–	3,145
Purchased power	–	882	302	–	1,184
Operation and maintenance	10	834	1,369	(371)	1,842
Depreciation, amortization and accretion	–	369	536	–	905
Taxes other than on income	–	309	202	(10)	501
Other	–	20	98	(88)	30
Total operating expenses	10	4,178	3,888	(469)	7,607
Operating (loss) income	(10)	590	888	78	1,546
Other income (expense)					
Interest income	27	8	24	(25)	34
Allowance for equity funds used during construction	–	41	10	–	51
Other, net	–	(2)	(9)	4	(7)
Total other income (expense), net	27	47	25	(21)	78
Interest charges					
Interest charges	203	210	219	(27)	605
Allowance for borrowed funds used during construction	–	(12)	(5)	–	(17)
Total interest charges, net	203	198	214	(27)	588
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(186)	439	699	84	1,036
Income tax (benefit) expense	(79)	117	297	(1)	334
Equity in earnings of consolidated subsidiaries	596	–	–	(596)	–
Income (loss) from continuing operations	489	322	402	(511)	702
Discontinued operations, net of tax	15	13	(137)	(97)	(206)
Net income (loss)	504	335	265	(608)	496
Net loss attributable to noncontrolling interests, net of tax	–	8	–	–	8
Net income (loss) attributable to controlling interests	$504	$343	$265	$(608)	$504

PEC

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2009				
Operating revenues	**$1,178**	**$1,076**	**$1,307**	**$1,066**
Operating income	**249**	**182**	**367**	**168**
Net income	**128**	**94**	**208**	**84**
Net income attributable to controlling interests	**128**	**95**	**208**	**85**
2008[a]				
Operating revenues	$1,068	$1,048	$1,266	$1,047
Operating income	240	205	353	198
Net income	123	104	201	106
Net income attributable to controlling interests	123	104	201	106

(a) Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. Typically, weather conditions in PEC's service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to its customers. As a result, its overall operating results may fluctuate substantially on a seasonal basis. During the fourth quarter of 2009, PEC recorded a cumulative prior period adjustment related to certain employee life insurance benefits. The impact of this adjustment decreased total other income, net, by $16 million and decreased net income attributable to controlling interests by $10 million. The prior period adjustment is not material to previously issued or current period financial statements.

PEF

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2009				
Operating revenues	**$1,262**	**$1,234**	**$1,516**	**$1,239**
Operating income	**140**	**195**	**314**	**153**
Net income	**89**	**119**	**177**	**77**
2008				
Operating revenues	$996	$1,194	$1,428	$1,113
Operating income	122	198	236	124
Net income	67	125	143	50

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. Typically, weather conditions in PEF's service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to its customers. As a result, its overall operating results may fluctuate substantially on a seasonal basis.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Fuel] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(8,365,798)		(8,365,798)		
2	225,244		225,244		
3	8,101,688	(562,456)	7,539,232		
4	8,326,932	(562,456)	7,764,476	385,018,788	392,783,264
5	(38,866)	(562,456)	(601,322)		
6	(38,866)	(562,456)	(601,322)		
7	17,285	272,008	289,293		
8	2,852,488	445,091	3,297,579		
9	2,869,773	717,099	3,586,872	462,182,514	465,769,386
10	2,830,907	154,643	2,985,550		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	12,204,243,382	12,201,712,142
4	Property Under Capital Leases	215,370,552	215,370,552
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	12,419,613,934	12,417,082,694
9	Leased to Others		
10	Held for Future Use	35,744,523	35,744,523
11	Construction Work in Progress	1,082,411,047	1,082,411,047
12	Acquisition Adjustments	18,261,333	18,261,333
13	Total Utility Plant (8 thru 12)	13,556,030,837	13,553,499,597
14	Accum Prov for Depr, Amort, & Depl	4,759,528,699	4,757,852,588
15	Net Utility Plant (13 less 14)	8,796,502,138	8,795,647,009
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,634,764,466	4,634,764,466
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	126,920,118	125,244,007
22	Total In Service (18 thru 21)	4,761,684,584	4,760,008,473
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	-2,155,885	-2,155,885
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,759,528,699	4,757,852,588

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
	2,531,240				3
					4
					5
					6
					7
	2,531,240				8
					9
					10
					11
					12
	2,531,240				13
	1,676,111				14
	855,129				15
					16
					17
					18
					19
					20
	1,676,111				21
	1,676,111				22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
	1,676,111				33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials	72,866	26,474
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	72,866	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	61,103,723	71,519,578
9	In Reactor (120.3)	104,936,776	625,793
10	SUBTOTAL (Total 8 & 9)	166,040,499	
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	60,032,977	20,082,414
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	106,080,388	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
	72,866	26,474	3
			4
			5
		26,474	6
			7
		132,623,301	8
		105,562,569	9
		238,185,870	10
			11
			12
		80,115,391	13
		158,096,953	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	8,450,028	
4	(303) Miscellaneous Intangible Plant	124,451,852	4,096,512
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	132,901,880	4,096,512
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	6,576,634	-1,306
9	(311) Structures and Improvements	305,882,598	97,001,358
10	(312) Boiler Plant Equipment	907,016,163	817,588,361
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	474,453,845	36,293,275
13	(315) Accessory Electric Equipment	161,888,778	111,899,674
14	(316) Misc. Power Plant Equipment	32,413,341	1,791,992
15	(317) Asset Retirement Costs for Steam Production	2,563,413	391,712
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,890,794,772	1,064,965,066
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	-365,040	316
19	(321) Structures and Improvements	233,920,024	8,319,294
20	(322) Reactor Plant Equipment	279,608,434	22,019,479
21	(323) Turbogenerator Units	94,173,012	1,992,850
22	(324) Accessory Electric Equipment	180,064,408	4,971,833
23	(325) Misc. Power Plant Equipment	43,628,954	4,491,846
24	(326) Asset Retirement Costs for Nuclear Production	18,697,977	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	849,727,769	41,795,618
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	16,544,863	666,505
38	(341) Structures and Improvements	173,154,502	52,480,351
39	(342) Fuel Holders, Products, and Accessories	111,739,239	37,711,764
40	(343) Prime Movers	1,041,762,382	494,019,093
41	(344) Generators	247,320,554	50,313,823
42	(345) Accessory Electric Equipment	140,154,567	23,306,472
43	(346) Misc. Power Plant Equipment	20,453,513	19,936,106
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,751,129,620	678,434,114
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,491,652,161	1,785,194,798

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			8,450,028		3
			128,548,364		4
			136,998,392		5
					6
					7
			6,575,328		8
10,755,831	-1,052,003	-8,133,566	382,942,556		9
83,781,855	-1,890,055	-1,758,142	1,637,174,472		10
					11
41,648,391	-53,633	-598,759	468,446,337		12
13,626,291		-903,589	259,258,572		13
2,825,971	-8,413	-653,099	30,717,850		14
	6,813,450		9,768,575		15
152,638,339	3,809,346	-12,047,155	2,794,883,690		16
					17
			-364,724		18
3,076,624	-1,225,182		237,937,512		19
341,751			301,286,162		20
868,788			95,297,074		21
573,503			184,462,738		22
1,421,822			46,698,978		23
			18,697,977		24
6,282,488	-1,225,182		884,015,717		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			17,211,368		37
105,873	1,052,003		226,580,983		38
599,732			148,851,271		39
28,811,213	215,059	12,047,155	1,519,232,476		40
305,462			297,328,915		41
706,964			162,754,075		42
161,255			40,228,364		43
					44
30,690,499	1,267,062	12,047,155	2,412,187,452		45
189,611,326	3,851,226		6,091,086,859		46

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	80,991,646	9,692,246
49	(352) Structures and Improvements	23,297,302	401,934
50	(353) Station Equipment	584,462,072	73,267,453
51	(354) Towers and Fixtures	66,261,042	3,503
52	(355) Poles and Fixtures	431,222,241	50,399,737
53	(356) Overhead Conductors and Devices	302,164,323	18,398,434
54	(357) Underground Conduit	7,010,980	46,720,808
55	(358) Underground Conductors and Devices	9,611,266	41,942,357
56	(359) Roads and Trails	3,133,902	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,508,154,774	240,826,472
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	31,233,444	4,213,826
61	(361) Structures and Improvements	26,483,666	-407,107
62	(362) Station Equipment	462,769,474	59,193,541
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	497,331,692	11,399,270
65	(365) Overhead Conductors and Devices	556,384,934	37,677,466
66	(366) Underground Conduit	216,680,178	10,338,002
67	(367) Underground Conductors and Devices	503,175,480	27,181,058
68	(368) Line Transformers	515,895,665	19,274,066
69	(369) Services	481,007,743	8,164,478
70	(370) Meters	120,557,384	2,044,039
71	(371) Installations on Customer Premises	2,666,792	391,724
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	293,793,186	10,379,736
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,707,979,638	189,850,099
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	9,969,556	909,147
87	(390) Structures and Improvements	110,455,851	4,201,685
88	(391) Office Furniture and Equipment	12,894,540	4,213,748
89	(392) Transportation Equipment	127,033,683	4,579,423
90	(393) Stores Equipment	3,858,273	611,451
91	(394) Tools, Shop and Garage Equipment	14,951,772	1,716,429
92	(395) Laboratory Equipment	971,682	104,375
93	(396) Power Operated Equipment	4,379,967	209,059
94	(397) Communication Equipment	66,254,242	2,089,733
95	(398) Miscellaneous Equipment	9,282,007	1,888,062
96	SUBTOTAL (Enter Total of lines 86 thru 95)	360,051,573	20,523,112
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	1,974,239	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	362,025,812	20,523,112
100	TOTAL (Accounts 101 and 106)	10,202,714,265	2,240,490,993
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	10,202,714,265	2,240,490,993

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
1,259	-1,151		90,681,482		48
55,408			23,643,828		49
10,023,544	447,840		648,153,821		50
			66,264,545		51
3,017,954	-433,956		478,170,068		52
2,110,523			318,452,234		53
108,158			53,623,630		54
			51,553,623		55
			3,133,902		56
					57
15,316,846	12,733		1,733,677,133		58
					59
			35,447,270		60
85,300			25,991,259		61
5,152,913	-587,326		516,222,776		62
					63
33,075			508,697,887		64
2,903,716	-206,091		590,952,593		65
31,019			226,987,161		66
2,539,569			527,816,969		67
9,396	206,091		535,366,426		68
468,736			488,703,485		69
			122,601,423		70
			3,058,516		71
					72
658,904			303,514,018		73
					74
11,882,628	-587,326		3,885,359,783		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
	-323,307		10,555,396		86
1,800,223			112,857,313		87
3,313,438	6,476,061		20,270,911		88
23,331,768			108,281,338		89
2,099,884			2,369,840		90
224,881			16,443,320		91
186,433			889,624		92
			4,589,026		93
2,257,367			66,086,608		94
141,497	499,778		11,528,350		95
33,355,491	6,652,532		353,871,726		96
					97
			1,974,239		98
33,355,491	6,652,532		355,845,965		99
250,166,291	9,929,165		12,202,968,132		100
					101
					102
					103
250,166,291	9,929,165		12,202,968,132		104

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	PERRY - CROSS CITY - DUNNELLON	10/87	12/2017	1,046,211
3	PERRY - FLORIDA STATE LINE	12/92	12/2017	1,808,764
4	HIGH SPRINGS - JASPER - FLORIDA STATE LINE	03/96	12/2017	2,584,486
5	BELCHER ROAD SUBSTATION	05/96	12/2009	267,012
6	LYBASS PROPERTY - LEVY COUNTY	12/07	12/2013	27,667,950
7	SUWANNEE LAND	12/09	06/2016	654,566
8	OTHER LAND AND RIGHTS < $25K EACH	07/90		962,673
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	PERRY - CROSS CITY - DUNNELLON	07/90	12/2017	752,861
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
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41				
42				
43				
44				
45				
46				
47	Total			35,744,523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	60LU1D STEAM GENERATOR MASTER	312,121,572
2	60CRNCR CAIR	268,318,544
3	60LU1D NPC EPU	157,780,007
4	60LX8D LAND - Levy BASELOAD Land, Long Lead Time & Pre-Construction	120,871,700
5	60KK8-1525T1 INT CITY-LOUGHMAN	28,939,851
6	60CR4CRP4 CT CATHODIC PROT	14,236,418
7	60GB9D CR3 LICENSE RENEWAL MAS	13,468,493
8	60CR4CRP3 CR4 TURBINE PROJECT	12,464,046
9	60KK8D 1907T2 BITHLO-OUC	9,862,515
10	60KK8D 1907D2 BITHLO 230/69KV	9,802,758
11	60KK8-1005T1 AVALON-GIFFORD	8,030,550
12	60LU1D SPENT FUEL DRY CASK	7,666,467
13	60CR5CRP4 CT CATHODIC PROT	7,599,743
14	60KK8-1005S1 GIFFORD NEW SUB	7,302,052
15	60KK8 CENTRAL FL SOUTH LAND	6,540,268
16	CATALYST 221 - PEF	5,793,779
17	60LU1D HOT LEG ALLOY 600 MITIG	5,340,853
18	60KK8-1005T2 BOGGY MARSH	5,178,438
19	60KK8D 1931S2 HAINES CITY EAST	4,343,392
20	60KK8D 2012S1 HOLDER DUNNELLON	3,144,052
21	60501D WILWOOD TRANS CTR	2,363,589
22	60034D-1767D1 PINELLAS WATER	2,211,936
23	60KK8-1794T1 PORT ST JOE-APALA	2,161,945
24	60KK8D 1716T1 FORT WHITE	2,149,750
25	60KK8D 1700T2 BELL TAP-BELL	2,087,530
26	60034-1017D2 CROWN PT NEW SUB	1,988,344
27	60GB9D ZTEF RCP-1B MOTR REWIND	1,912,686
28	CP HEC PB1B 2010 SPR MOD HGP	1,871,758
29	60034D_982D1_SHINGLE CREEK	1,865,908
30	60CR5CRP4 HIGH SULFR ASH BLR	1,804,234
31	60X00D 09 VEH LSED ASSET	1,714,907
32	60KK8-1711T1 WILLISTON CARA	1,649,100
33	60034-1017T1 CLARCONA CROWN PT	1,579,696
34	60KK8-1525S1 INT CITY TERM	1,534,165
35	60KK8D 1983T1 RIO PINAR-E ORNG	1,029,804
36	Other Minor Project	45,680,197
37		
38		
39		
40		
41		
42		
43	TOTAL	1,082,411,047

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	4,562,794,903	4,562,794,903		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	330,920,466	330,920,466		
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,729,761	2,729,761		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	6,520,625	6,520,625		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock - Oil & Rail Cars	1,587,831	1,587,831		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	341,758,683	341,758,683		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	250,166,291	250,166,291		
13	Cost of Removal	64,203,955	64,203,955		
14	Salvage (Credit)	43,379,741	43,379,741		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	270,990,505	270,990,505		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	Transfers/Adjustments	1,201,385	1,201,385		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,634,764,466	4,634,764,466		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,320,947,011	1,320,947,011		
21	Nuclear Production	588,392,076	588,392,076		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	617,168,147	617,168,147		
25	Transmission	487,291,520	487,291,520		
26	Distribution	1,509,513,184	1,509,513,184		
27	Regional Transmission and Market Operation				
28	General	111,452,527	111,452,527		
29	TOTAL (Enter Total of lines 20 thru 28)	4,634,764,465	4,634,764,465		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 14 Column: c

Salvage by Type:	
Salvage Restocked	$39,079,459.94
Salvage Scrap	2,740,989.91
Salvage Reinstalled	1,559,296.00
Total Salvage	$43,379,745.85

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	326,907,773	362,905,373	
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	131,197,757	175,846,999	Various
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	71,315,414	69,391,351	Power Supply
8	Transmission Plant (Estimated)	4,422,282	3,214,854	Transmission
9	Distribution Plant (Estimated)	18,592,364	14,021,765	Customer Service
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,654,446	1,321,909	Various
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	227,182,263	263,796,878	
13	Merchandise (Account 155)	505,165	618,787	Customer Service
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	22,069,958	8,181,652	Various
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	576,665,159	635,502,690	

Schedule Page: 227 Line No.: 12 Column: b

Account 154 Plant Materials and Operating Supplies includes an Inventory reserve account, credit balance of $1,082,359. During 2008, $2,689,989 was charged and $2,409,318 was credited against this reserve account. Current reserve levels are sufficient based on current inventory reviews.

Account 154 Plant Materials and Operating Supplies is a net balance and excludes the co-owned inventory balance of $5,182,150. Co-owned inventory accounts include Crystal River Unit 3 valued at $3,354,605 and Intercession City, Siemens Unit 11 valued at $1,827,545 at the end of 2008.

Account 154 Plant Materials and Operating Supplies - Assigned to Other, represents inventory for Telecommunication and Corporate facilities that cannot be readily assigned to a specific primary function.

Schedule Page: 227 Line No.: 12 Column: c

Account 154 Plant Materials and Operating Supplies includes an Inventory reserve account, credit balance of $1,700,000. During 2009, $617,641 was credited to this reserve account. Current reserve levels are sufficient based on current inventory reviews.

Account 154 Plant Materials and Operating Supplies is a net balance and excludes the co-owned inventory balance of $5,593,109. Co-owned inventory accounts include Crystal River Unit 3 valued at $3,768,333 and Intercession City, Siemens Unit 11 valued at $1,824,776 at the end of 2009.

Account 154 Plant Materials and Operating Supplies - Assigned to Other, represents inventory for Telecommunication and Corporate facilities that cannot be readily assigned to a specific primary function.

Schedule Page: 227 Line No.: 16 Column: b

Account 163 - Stores Expense Undistributed - Allocations accounts were charged with $2,916,493 and credited with $2,437,397 for a net charge of $479,096 during 2008. These charges to operations, maintenance and capital accounts were to record various inventory adjustments for 2008.

Schedule Page: 227 Line No.: 16 Column: c

Account 163 Stores Expense Undistributed - Allocations accounts were charged with $3,018,610 and credited with $3,484,533 for a net credit of $465,923 during 2009. These charges to operation, maintenance and capital accounts were to record various inventory adjustments for 2009

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2010 No. (d)	2010 Amt. (e)
1	Balance-Beginning of Year	201,249.00	9,783,195	124,141.00	281,600
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Transfer Southern Company	361.00			
10					
11					
12					
13					
14					
15	Total	361.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	81,401.00	3,879,064		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	120,209.00	5,904,131	124,141.00	281,600
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	3,343.00		3,343.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year	3,343.00		3,343.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	1,697.00	120,175		
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2011		2012		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
124,499.00	281,600	124,141.00	281,600	2,301,509.00	563,200	2,875,539.00	11,191,195	1
								2
								3
				925,120.00		925,120.00		4
								5
								6
								7
								8
						361.00		9
								10
								11
								12
								13
								14
						361.00		15
								16
								17
358.00						81,759.00	3,879,064	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
124,141.00	281,600	124,141.00	281,600	3,226,629.00	563,200	3,719,261.00	7,312,131	29
								30
								31
								32
								33
								34
								35
3,343.00		3,343.00		67,600.00		80,972.00		36
								37
								38
								39
3,343.00		3,343.00		67,600.00		80,972.00		40
								41
								42
								43
				1,693.00	11,444	3,390.00	131,619	44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2010 No. (d)	2010 Amt. (e)
1	Balance-Beginning of Year	40,539.00	42,141,570	26,104.00	5,730,425
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,235.00		839.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:	2,750.00	10,417,750	1,155.00	
9	vendors in footnote				
10					
11					
12					
13					
14					
15	Total	2,750.00	10,417,750	1,155.00	
16					
17	Relinquished During Year:				
18	Charges to Account 509	32,244.00	41,656,638		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	12,280.00	10,902,682	28,098.00	5,730,425
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2011		2012		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
27,446.00	7,442,175	25,794.00	4,785,925	1,675.00	5,410,725	121,558.00	65,510,820	1
								2
								3
						2,074.00		4
								5
								6
								7
300.00	517,500	300.00	517,500	600.00	1,035,000	5,105.00	12,487,750	8
								9
								10
								11
								12
								13
								14
300.00	517,500	300.00	517,500	600.00	1,035,000	5,105.00	12,487,750	15
								16
								17
						32,244.00	41,656,638	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
27,746.00	7,959,675	26,094.00	5,303,425	2,275.00	6,445,725	96,493.00	36,341,932	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 8 Column: b

Allowances Acquired From:

Constellation
Duke Carolina
Koch Supply
AEP
DTE Coal
Duke Indiana
NRG

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	Storm Extraordinary Property Loss					
2	Wholesale (FERC letter dated					
3	1/7/2005. Docket No. AC05-12-000					
4	amortization expenses consistent					
5	with recovery in rates.)	13,668,566		4073701	3,167,206	10,501,360
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL	13,668,566			3,167,206	10,501,360

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Accumulated Deferred Taxes - FAS 109	162,573,470	68,039,161	4101000	17,491,449	213,121,182
2	as temporary differences occur.					
3						
4	Load Control Switches - Investment	11,842,340	5,315,089	1823310	763,064	16,394,365
5	Load Control Switches - Amortization	(3,208,270)	763,064	9080120	2,962,384	-5,407,590
6						
7	Interest on Tax Deficiency		3,228,952	4310024	614,616	2,614,336
8						
9	Deferred GPIF Asset	2,167,933		4560096	2,167,933	
10	Deferred Fuel Expense - Full Req	5,575,881	4,479,412	5572002	4,934,528	5,120,765
11	Deferred Fuel Expense - Current Year	128,477,178	47,188,107	5572002	175,665,285	
12	Deferred Fuel Expense - Prior Year		146,154,866	5572002	146,154,866	
13	Deferred Capacity Expense - Prior Year	(2,181,229)	2,181,229	5572001		
14	Deferred Capacity Expense - Current Year		409,997,225	5572001	364,386,539	45,610,686
15						
16	Deferred Environmental Cost Recovery	8,248,191	1,543,510	4073006	9,791,701	
17	Accrued Environmental Cost Recovery	21,317,364	11,884,662	2284800	13,900,025	19,302,001
18						
19	Florida Minimum Pension Liability	519,711,662	30,696,940	2283151-70	99,714,212	450,694,390
20						
21	Regulatory Asset Derivative MTM Oil	600,900,522	235,997,400	2543015-17	489,212,866	347,685,056
22						
23	Regulatory Asset - FAS 143 Asbestos	6,061,226	3,063,161	4074002	7,562,288	1,562,099
24	Regulatory Asset - FAS 143 Landfill		5,554,045	4074002	129,396	5,424,649
25						
26	Deferred Levy - 2010 Regulatory Asset		273,889,606			273,889,606
27	Deferred Levy Nuclear - Current Year	180,942,559	283,082,251	4073005	464,024,810	
28	Deferred Levy Nuclear - Prior Year		345,566,971	4073005	343,969,084	1,597,887
29	Deferred CR3 NCR - Current Year	8,546,392	20,785,092	4073005	28,552,566	778,918
30	Deferred CR3 NCR - Prior Year		14,123,822	4073005	14,123,822	
31						
32	Regulatory Asset - 2009 Pension		33,805,589			33,805,589
33						
34	Regulatory Asset - Medicare Part D		6,557,667	1823050	28,609,944	-22,052,277
35						
36	Base Rate Regulatory Asset		1,436,902			1,436,902
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,650,975,219	1,955,334,723		2,214,731,378	1,391,578,564

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Job Orders Work in Process	226,480	3,836,986	Various	3,554,415	509,051
2	Southern Company Capacity	803,433				803,433
3	G2 Energy Pre-construction	259,645	53,614	Various	313,259	
4	Fay Storm	9,768,755	1,660,216	Various	11,428,972	-1
5	F&H Gulf Blvd Project	210,822	8,433	Various	118,061	101,194
6	FL Rate Case	332,517	3,360,989	Various	1,302,224	2,391,282
7	Vacation Pay Accrual	7,435,644	2,715,638	242	7,441,947	2,709,335
8	Labor Accrual	2,831,862	46,643,216	242	44,234,334	5,240,744
9	Zephyrhills	400,000				400,000
10	SECI-Interconnection Upgrade		1,126,148	Various		1,126,148
11	Worker's Comp		2,498,266	Various	961,785	1,536,481
12	Int on Tax Deficiency-LT Asset		4,046,631	Various		4,046,631
13	Coal Mine Safety	245,873	330,365	Various		576,238
14	Gov Imposition	14,259		Various	14,259	
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
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37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	22,529,290				19,440,536

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	UNBILLED REVENUE	42,844,000	47,987,828
3	LIFE/MEDICAL BENEFITS	114,831,000	100,612,338
4	UNAMORTIZED INVESTMENT TAX CREDIT	4,439,000	2,685,016
5	REGULATORY LIABILITY	12,215,000	9,744,653
6	NUCLEAR DECOMMISSIONING	40,023,000	80,813,112
7	OTHER	428,421,374	299,205,115
8	TOTAL Electric (Enter Total of lines 2 thru 7)	642,773,374	541,048,062
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	642,773,374	541,048,062

Notes

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	60,000,000		
2	Total Common Stock	60,000,000		
3	Cumulative Preferred Stock	4,000,000		
4	4.00% Series		100.00	104.25
5	4.60% Series		100.00	103.25
6	4.75% Series		100.00	102.00
7	4.40% Series		100.00	102.00
8	4.58% Series		100.00	101.00
9	Cumulative Preferred Stock	5,000,000		
10	Preference Stock	1,000,000	100.00	
11	Total Preferred Stock	10,000,000		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
100	354,405,315					2
100	354,405,315					3
						4
39,980	3,998,000					5
39,997	3,999,700					6
80,000	8,000,000					7
75,000	7,500,000					8
99,990	9,999,000					9
						10
						11
334,967	33,496,700					12
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	ACCOUNT 211 - MISCELLANEOUS PAID IN CAPITAL	
2	Donations by General Gas & Electric Corporation (Former Parent)	419,213
3	Excess of Stated Value of 3,000,000 shares of Common Stock	
4	exchanged for 857, 143 shares at $7.50 par value Common Stock and	
5	miscellaneous adjustments applicable to exchange	326,032
6	Excess of Net Worth of Assets at date of Merger (12/31/43)	
7	over stated value of Common Stock issued therefore	1,167,518
8	Florida Public Service 4% Series "C" Bonds with called premium and	
9	interest held by General Gas and Electric Corporation	65,210
10	Reversal of over accrual of Federal Income Tax applicable to period	
11	prior to January 1, 1944	262,837
12	Transfer from Earned Surplus amount equivalent to Preferred Stock	
13	Dividends prior to 12/31/43 which on an accrual basis were applicable	
14	to 1944	92,552
15	To write off unamortized debt discount, premium and expense applicable	-979,793
16	to Bonds refunded in prior years	
17	Adjustment of original cost of Florida Public Service Company	
18	resulting in examination by Federal Power Commission	-63,027
19	Adjustment in carrying value of Georgia Power & Light Company Common	
20	Stock occasioned by the subsidiary company's increase in capital	
21	surplus	33,505
22	Capital Contribution from Parent Company	1,359,992,013
23	Other Miscellaneous adjustments	45,211
24	Payroll taxes associated with stock option exercises	1,260,482
25	Misc PIC - Stock Options	655,780
26	Misc PIC - Performance Share Sub Plan (PSSP)	12,129,793
27	Misc PIC - Restricted Stock Units (RSU)	14,053,825
28		
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40	TOTAL	1,389,461,151

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	First Mortgage Bonds - 6.65%	300,000,000	3,182,657
2			429,000 D
3	First Mortgage Bonds - 4.8%	425,000,000	4,585,299
4			1,513,000 D
5	First Mortgage Bonds - 5.9%	225,000,000	3,013,280
6			571,500 D
7	First Mortgage Bonds - 5.1%	300,000,000	3,473,110
8			594,000 D
9	First Mortgage Bonds - 4.5%	300,000,000	3,291,598
10			915,000 D
11	Medium Term Note - 6.75%	150,000,000	5,528,498
12			436,500 D
13	Pollution Control Bonds (Citrus) 2002A	108,550,000	2,356,705
14			
15	Pollution Control Bonds (Citrus) 2002B	100,115,000	2,081,983
16			D
17	Pollution Control Bonds (Citrus) 2002C	32,200,000	756,175
18			D
19	RCA - 5 Year		1,009,474
20			
21	First Mortgage Bonds - 6.35%	500,000,000	6,708,137
22			660,000 D
23	First Mortgage Bonds - 5.80%	250,000,000	2,959,477
24			672,500 D
25	First Mortgage Bonds - 5.65%	500,000,000	5,559,462
26			1,805,000 D
27	First Mortgage Bonds - 6.40%	1,000,000,000	13,136,457
28			4,220,000 D
29			
30			D
31			
32			D
33	TOTAL	4,190,865,000	69,458,812

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
				300,000,000	19,950,000	1
7/18/01	7/15/11	7/18/01	7/15/11			2
				425,000,000	20,400,000	3
2/21/03	3/1/13	2/21/03	3/1/13			4
				225,000,000	13,275,000	5
2/21/03	2/15/33	2/21/03	2/15/33			6
				300,000,000	15,300,000	7
11/21/03	12/1/15	11/21/03	12/1/15			8
				300,000,000	13,500,000	9
5/16/05	6/1/10	5/16/05	6/1/10			10
				150,000,000	10,125,000	11
2/13/98	2/01/28	2/13/98	2/01/28			12
				108,550,000	807,911	13
8/20/02	1/01/27	8/20/02	1/01/27			14
				100,115,000	681,113	15
7/24/02	1/01/22	7/24/02	1/01/22			16
				32,200,000	252,648	17
8/13/02	1/01/18	8/13/02	1/01/18			18
						19
3/28/05	3/28/11	3/28/05	3/28/11			20
				500,000,000	32,068,629	21
9/12/07	9/15/37	9/12/07	9/15/37			22
				250,000,000	14,915,689	23
9/12/07	9/15/17	9/12/07	9/15/17			24
				500,000,000	27,801,293	25
6/15/08	6/15/18	6/15/08	6/15/18			26
				1,000,000,000	63,709,946	27
6/15/08	6/15/38	6/15/08	6/15/38			28
						29
						30
						31
						32
				4,190,865,000	232,787,229	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	462,182,514
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Income Tax Deducted for Books	177,447,448
11		
12	Deductions Recorded on Books Not Deducted for Return	1,472,955,851
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Deductions on Return Not Charged Against Book Income	1,571,899,688
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	540,686,125
28	Show Computation of Tax:	
29	Provision for Federal Income Tax at 35%	189,240,144
30	True up Entries and Other Tax Benefits	-63,991,242
31	Total Federal Income Tax Provision (409120F - 409220F) True up Entries	125,248,902
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL TAXES					
2	Income	-36,401,604		125,248,902	191,067,128	
3	FICA	15,299		25,982,223	25,988,834	
4	Unemployment	6,115		264,307	256,108	
5	Special Fuel Tax					
6	Excise Tax					
7	Highway Use			39,833	39,833	
8	Payroll Tax	1,858,148		535,564		
9	SUBTOTAL	-34,522,042		152,070,829	217,351,903	
10						
11	STATE TAXES					
12	Income	-9,090,366		19,655,136	27,212,286	
13	Income Tax Subsidiary					
14	Gross Receipts	7,339,536		114,856,185	114,452,318	
15	Unemployment	19,720		673,840	657,098	
16	Intangibles					
17	Regulatory Assessment	1,581,603		3,415,930	3,194,551	
18	Sales Tax-Company Use	13,222		269,603	197,944	
19	SUBTOTAL	-136,285		138,870,694	145,714,197	
20						
21	COUNTY & LOCAL TAXES					
22	Property-County & Local	580		97,553,459	97,554,620	
23	FL Privilege License					
24	Franchise-Local	7,049,842		109,954,666	109,701,533	
25						
26						
27	Adj-Use Tax on Purchases					
28	SUBTOTAL	7,050,422		207,508,125	207,256,153	
29						
30						
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38						
39						
40						
41	TOTAL	-27,607,905		498,449,648	570,322,253	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-102,219,830		124,552,573			696,329	2
8,688		21,360,718			4,621,504	3
14,313					264,307	4
						5
						6
		39,833				7
2,393,711					535,564	8
-99,803,118		145,953,124			6,117,704	9
						10
						11
-16,647,516		20,553,896			-898,760	12
						13
7,743,403		114,856,185				14
36,462					673,840	15
						16
1,802,983		3,415,930				17
84,881		269,603				18
-6,979,787		139,095,614			-224,920	19
						20
						21
-581		97,045,754			507,705	22
						23
7,302,975		110,009,364			-54,698	24
						25
						26
						27
7,302,394		207,055,118			453,007	28
						29
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						40
-99,480,511		492,103,856			6,345,791	41

Schedule Page: 262 Line No.: 27 Column: g

Page 112, Line 37, Column d

The difference between the Taxes Accrued amount on Page 112, Line 37 and Taxes Accrued on Page 262 - 263, Col. (b) & (g) are for exclusions of Sales Taxes per instruction #1 on Page 262.

Taxes Accrued, P. 112, Line 37	(27,105,282)	(99,172,450)
State Sales Tax on Purchases	(491,012)	(278,086)
County Sales Tax on Purchases	(11,610)	(29,975)
	(27,607,904)	(99,480,511)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	11,506,508			4114001	4,545,996	
6							
7							
8	TOTAL	11,506,508				4,545,996	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
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11							
12							
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15							
16							
17							
18							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
6,960,512	27 Years		6
			7
			8
6,960,512			9
			10
			11
			12
			13
			14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Wholesale Deposits - SECI	5,500,000	131	500,000		5,000,000
2	Wholesale Deposits - Other	221,150	253		46,349	267,499
3	Wholesale Deposits - FMPA	1,260,000	131		200,000	1,460,000
4	Interest on Tax Deficiency	15,285,818	various	18,723,602	3,437,784	
5	12K Basket Upgrade	6,627,248	107	9,842,379	6,950,755	3,735,624
6	Cable and Other Deposits	1,960,901	131, 242	1,600,748	412,126	772,279
7	Deferred Rent Expense	339,717	242, 931	93,592	196,046	442,171
8	Franchise Settlements	1,330,000	131	254,000	200,000	1,276,000
9	PEP Lease Incentives	3,586,959	242	377,966		3,208,993
10	Feasibility Study	1,002,207	186	370,925	20,060	651,342
11	PTC Fiber 400 Indemnification	7,125,484	242	361,399		6,764,085
12	Joint Owner	-1,906,880	various	10,601,061	12,250,344	-257,597
13	Various	8,927	various	5,261,210	5,252,283	
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
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26						
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36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	42,341,531		47,986,882	28,965,747	23,320,396

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	4,083,000	-325,410	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	4,083,000	-325,410	
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	4,083,000	-325,410	
18	Classification of TOTAL			
19	Federal Income Tax	3,498,000	-276,165	
20	State Income Tax	585,000	-49,245	
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
						3,757,590	4
							5
							6
							7
						3,757,590	8
							9
							10
							11
							12
							13
							14
							15
							16
						3,757,590	17
							18
						3,221,835	19
						535,755	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	547,273,147	21,307,894	
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	547,273,147	21,307,894	
6	Other			
7	Other			
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	547,273,147	21,307,894	
10	Classification of TOTAL			
11	Federal Income Tax	473,871,040	18,503,366	
12	State Income Tax	73,402,107	2,804,528	
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
35,533,496				19011 /409.1	56,068,920	660,183,457	2
							3
							4
35,533,496					56,068,920	660,183,457	5
							6
							7
							8
35,533,496					56,068,920	660,183,457	9
							10
30,467,152					48,312,924	571,154,482	11
5,066,344					7,755,996	89,028,975	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: i

Adjustments to 282 - Various Accounts

Credits to 282 - Debits to Various Accounts

19011FE	17,927,705
19011FL	2,981,175
409120F	30,385,219
409120J	4,774,821
TOTAL	56,068,920

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Assets - FAS 109	62,706,000	-2,591,980	
4				
5				
6				
7				
8	Other	587,164,342	-71,039,521	-5,772,378
9	TOTAL Electric (Total of lines 3 thru 8)	649,870,342	-73,631,501	-5,772,378
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	649,870,342	-73,631,501	-5,772,378
20	Classification of TOTAL			
21	Federal Income Tax	557,903,383	-63,772,804	-4,938,759
22	State Income Tax	91,966,959	-9,858,697	-833,619
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
22,097,293						82,211,313	3
							4
							5
							6
							7
		190.1	16,462,455	219	300	505,435,044	8
22,097,293			16,462,455		300	587,646,357	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
22,097,293			16,462,455		300	587,646,357	19
							20
18,946,674			14,115,247		258	503,901,023	21
3,150,619			2,347,208		42	83,745,334	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: g

Adjustments to 283 - Various Accounts

Debits to 283 - Credits to Various Accounts

19010FE	(12,420)
19010FL	(2,066)
19011FE	(14,102,827)
19011FL	(2,345,142)
Total Credits	(16,462,455)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Accumulated Deferred Taxes - FAS 109	31,664,516	4111000	6,403,937		25,260,579
2	Period of Amortization occurs as					
3	temporary differences occur.					
4						
5	Deferred GPIF Penalty				531,150	531,150
6	Regulatory Liability Fuel	4,812,652	5572002	13,832,981	17,686,563	8,666,234
7	Deferred Fuel Revenue - Current Year		5572002	108,263,153	129,712,876	21,449,723
8	Deferred Fuel Revenue - Prior Year	(16,807,030)			17,677,688	870,658
9	Deferred Capacity Revenue - Cur Yr.	15,641,399	5572001	15,641,399		
10	Deferred Capacity Revenue - Pr. Yr.		5572001	15,292,976	17,822,629	2,529,653
11						
12	Deferred Environmental Cost Recovery		4074017	3,238,365	27,507,275	24,268,910
13						
14	ARO - Nuclear Decom Trust Unrl Gains	7,197,115	1289191	7,197,115		
15	ARO - SFAS 143 Nuclear Decom	71,216,369	4073002	48,136,352	3,294,557	26,374,574
16	ARO - SFAS 143 Asbestos	4,537,508	4073002	4,557,595	3,468,549	3,448,462
17	NDT - Qualified - Unrealized Gains		1289191	23,687,399	137,913,165	114,225,766
18						
19	Auctioned S02 Allowance	2,063,253	4070004	15,073,159	14,931,620	1,921,714
20						
21	Winter Park Stranded Costs-6/05-12/10	1,553,972	4560001	765,000		788,972
22						
23	Regulatory Liability Derivative MTM Oil	25,958,504	1823015	48,652,538	42,399,834	19,705,800
24						
25	Deferred Energy Conservation	6,495,557	9080110	7,120,216	2,583,092	1,958,433
26						
27	Deferred Levy Nuclear - Current Year		4074005	150,983	1,168,672	1,017,689
28	Deferred CR3 Nuclear - Current Year		4074005	1,525,284	1,525,284	
29	Deferred CR3 Nuclear - Prior Year				11,102	11,102
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	154,333,815		319,538,452	418,234,056	253,029,419

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	2,662,663,874	2,273,649,602
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,314,070,181	1,127,543,766
5	Large (or Ind.) (See Instr. 4)	325,100,344	308,064,952
6	(444) Public Street and Highway Lighting	2,189,288	1,841,868
7	(445) Other Sales to Public Authorities	343,810,186	291,612,950
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,647,833,873	4,002,713,138
11	(447) Sales for Resale	410,163,456	548,740,574
12	TOTAL Sales of Electricity	5,057,997,329	4,551,453,712
13	(Less) (449.1) Provision for Rate Refunds	68,669	1,474,329
14	TOTAL Revenues Net of Prov. for Refunds	5,057,928,660	4,549,979,383
15	Other Operating Revenues		
16	(450) Forfeited Discounts	23,572,819	22,775,140
17	(451) Miscellaneous Service Revenues	23,536,571	24,254,337
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	85,804,361	82,583,176
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	59,779,302	51,298,452
22	(456.1) Revenues from Transmission of Electricity of Others		
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	192,693,053	180,911,105
27	TOTAL Electric Operating Revenues	5,250,621,713	4,730,890,488

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
19,399,195	19,328,406	1,441,325	1,449,041	2
				3
11,883,477	12,138,923	161,390	162,569	4
3,285,389	3,786,296	2,487	2,587	5
25,968	26,271	1,624	1,652	6
3,230,223	3,275,813	23,346	23,062	7
				8
				9
37,824,252	38,555,709	1,630,172	1,638,911	10
4,041,389	6,777,353	23	24	11
41,865,641	45,333,062	1,630,195	1,638,935	12
				13
41,865,641	45,333,062	1,630,195	1,638,935	14

Line 12, column (b) includes $ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 17 Column: b

Includes revenues of $23,507,174 from service charges billed to customers for establishment of new service, reconnection of service, and transfer of account from one occupant to another.

Schedule Page: 300 Line No.: 19 Column: b

Includes revenues of: $51,614,237 from Wheeling-Transmission; $9,255,091 from Retail Unbilled revenue; ($3,713,552) from Wholesale Unbilled revenue; ($2,699,083) from Generation Performance Incentive Factor; $3,665,151 from Wheeling Production Ancillary services; $488,537.33 from Wheeling Tariff Retail CCR; and $821,271 from Other Misc Electric revenues.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Services	19,399,195	2,662,663,874	1,441,325	13,459	0.1373
2						
3	Commercial and Industrial Service	15,168,866	1,639,170,525	163,877	92,563	0.1081
4						
5	Public Street and Highway Lightin	25,968	2,189,288	1,624	15,990	0.0843
6						
7	Other Sales to Public Authorities	3,230,223	343,810,186	23,346	138,363	0.1064
8						
9	Total Sales to Ultimate Customers	37,824,252	4,647,833,873	1,630,172	23,203	0.1229
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	CITY OF BARTOW	RQ	TARIFF NO. 9	59	59	59
2	CITY OF CHATTAHOOCHEE	RQ	FERC NO. 126	6	6	6
3	CITY OF HOMESTEAD	RQ	TARIFF NO. 9	30	30	30
4	CITY OF KISSIMMEE	RQ	FERC NO. 120	0	0	0
5	CITY OF DORA	RQ	FERC NO. 127	20	23	23
6	CITY OF NEW SMYRNA BEACH	RQ	FERC NO. 144	24	23	23
7	CITY OF QUINCY	RQ	TARIFF NO. 01	20	20	20
8	CITY OF ST. CLOUD	RQ	FERC NO. 121	0	0	0
9	CITY OF TALLAHASSEE	RQ	FERC NO. 178	11	0	0
10	CITY OF WILLISTON	RQ	FERC NO. 124	7	7	7
11	CITY OF WINTER PARK	RQ	FERC NO. 191	85	85	0
12	FLORIDA MUNICIPAL POWER AGENCY	RQ	FERC NO. 107	141	62	56
13	REEDY CREEK IMPROVEMENT DISTRICT	RQ	FERC NO. 118	99	101	101
14	SEMINOLE ELECTRIC COOPERATIVE, INC	RQ	FERC NO. 106	860	621	761
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
300,591	6,410,924	18,606,205		25,017,129	1
31,794	705,155	2,039,422	3,168	2,747,745	2
193,872	4,581,250	9,965,677		14,546,927	3
			8,004	8,004	4
96,366	2,193,351	5,986,292		8,179,643	5
89,964	3,460,200	5,300,213	83	8,760,496	6
100,561	2,114,412	6,228,373		8,342,785	7
			996	996	8
99,867	-234,361	4,370,754		4,136,393	9
35,092	621,986	2,476,618		3,098,604	10
444,958	8,408,249	27,725,006		36,133,255	11
156,769	19,191,636	9,153,089	103,600	28,448,325	12
417,205	14,982,960	20,364,890	33,984	35,381,834	13
1,217,505	86,548,925	71,635,681	756,479	158,941,085	14
3,696,172	186,798,602	209,146,538	906,314	396,851,454	
345,217	0	13,465,798	-153,796	13,312,002	
4,041,389	186,798,602	222,612,336	752,518	410,163,456	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SOUTHEASTERN POWER ADMIN	RQ	FERC NO. 65	21	0	0
2	TAMPA ELECTRIC COMPANY	RQ	FERC NO. 07	85	125	125
3	CITY OF GAINSVILLE	RQ	FERC NO. 88	85	79	78
4						
5						
6						
7						
8	NON-REQUIREMENTS SERVICE					
9	CONOCO PHILLIPS	OS	FERC NO.10			
10	COBB ELECTRIC MEMBERSHIP CORP	OS	FERC NO. 10			
11	CARGILL-ALLIANT	OS	FERC NO. 8			
12	DUKE POWER COMPANY	OS	FERC NO. 10			
13	FLORIDA MUNICIPAL POWER AGENCY	OS	FERC NO. 105			
14	FLORIDA POWER & LIGHT CO	OS	FERC NO. 81/02			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
40,305	651,415	2,227,267		2,878,682	1
224,985	18,200,000	10,887,586		29,087,586	2
246,338	18,962,500	12,179,465		31,141,965	3
					4
					5
					6
					7
					8
1,671		49,873		49,873	9
16,571		545,848		545,848	10
9,096		309,666		309,666	11
950		19,177		19,177	12
518		20,687		20,687	13
4,650		253,693		253,693	14
3,696,172	186,798,602	209,146,538	906,314	396,851,454	
345,217	0	13,465,798	-153,796	13,312,002	
4,041,389	186,798,602	222,612,336	752,518	410,163,456	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	GAINESVILLE REGIONAL UTILITIES	OS	FERC NO. 88			
2	NEW SMYRNA BEACH, CITY OF	OS	FERC NO. 104			
3	OGLETHORPE	OS	FERC NO. 139			
4	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86			
5	PJM INTERCONNECTION, LLC	OS	PJM			
6	PJM INTERCONNECTION, LLC	AD	PJM			
7	REEDY CREEK UTILITIES	OS	FERC NO. 119			
8	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128			
9	SOUTHERN COMPANY SERVICES	OS	FERC NO. 111			
10	TALLAHASSEE, CITY OF (1)	OS	FERC NO. 122			
11	THE ENERGY AUTHORITY	OS	FERC NO. 175			
12	TAMPA ELECTRIC CO	OS	FERC NO. 80			
13	TENNESSEE VALLEY AUTHORITY	OS	FERC NO. 138			
14	CONSTELLATION ENERGY COMMODITIES	OS	FERC No. 8			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
100		3,848		3,848	1
14,548		921,662	-153,799	767,863	2
5,520		179,742		179,742	3
2,818		100,003		100,003	4
8,593		473,149		473,149	5
			3	3	6
82,157		2,620,323		2,620,323	7
95,431		4,558,591		4,558,591	8
6,945		209,377		209,377	9
1,770		126,642		126,642	10
52,827		1,613,900		1,613,900	11
22,607		793,121		793,121	12
2,177		84,082		84,082	13
16,268		582,414		582,414	14
3,696,172	186,798,602	209,146,538	906,314	396,851,454	
345,217	0	13,465,798	-153,796	13,312,002	
4,041,389	186,798,602	222,612,336	**752,518**	410,163,456	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 310.1 Line No.: 8 Column: a

Schedule Page: 310.2 Line No.: 2 Column: a

2009 OS Sales for New Smyrna Beach, City of includes ($153,799) capacity credit.

Schedule Page: 310.2 Line No.: 6 Column: a

OUT-OF-PERIOD ADJUSTMENT - PJM INTERCONNECTION, LLC - $2.87.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	8,897,573	7,921,409
5	(501) Fuel	700,981,678	952,698,616
6	(502) Steam Expenses	8,219,861	8,621,084
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.	-139	
9	(505) Electric Expenses	8,031	34,116
10	(506) Miscellaneous Steam Power Expenses	14,364,266	21,643,764
11	(507) Rents		
12	(509) Allowances	45,535,702	14,757,443
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	778,007,250	1,005,676,432
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	5,142,489	2,081,404
16	(511) Maintenance of Structures	3,235,036	4,017,547
17	(512) Maintenance of Boiler Plant	20,795,491	11,456,972
18	(513) Maintenance of Electric Plant	5,745,662	3,920,387
19	(514) Maintenance of Miscellaneous Steam Plant	16,097,491	24,954,101
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	51,016,169	46,430,411
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	829,023,419	1,052,106,843
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	2,074,759	1,292,454
25	(518) Fuel	26,360,191	32,072,560
26	(519) Coolants and Water	5,519,110	4,202,627
27	(520) Steam Expenses	10,557,228	10,768,233
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	12,574	3,563
31	(524) Miscellaneous Nuclear Power Expenses	44,023,473	42,571,657
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	88,547,335	90,911,094
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	13,072,406	10,666,664
36	(529) Maintenance of Structures	3,027,873	1,758,489
37	(530) Maintenance of Reactor Plant Equipment	18,402,830	15,750,492
38	(531) Maintenance of Electric Plant	4,693,195	1,881,696
39	(532) Maintenance of Miscellaneous Nuclear Plant	4,565,818	2,904,562
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	43,762,122	32,961,903
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	132,309,457	123,872,997
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	5,905,526	3,961,518
63	(547) Fuel	1,192,514,722	1,005,783,068
64	(548) Generation Expenses	11,159,109	7,795,973
65	(549) Miscellaneous Other Power Generation Expenses	12,851,397	8,973,220
66	(550) Rents	100,794	145,650
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,222,531,548	1,026,659,429
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,035,058	1,092,264
70	(552) Maintenance of Structures	723,249	760,835
71	(553) Maintenance of Generating and Electric Plant	18,938,093	11,980,541
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	8,870,977	20,411,713
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	29,567,377	34,245,353
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	1,252,098,925	1,060,904,782
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	742,605,910	921,860,536
77	(556) System Control and Load Dispatching	2,183,045	2,264,532
78	(557) Other Expenses	66,726	12,793
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	744,855,681	924,137,861
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,958,287,482	3,161,022,483
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,909,806	4,828,865
84	(561) Load Dispatching	42,374	43,872
85	(561.1) Load Dispatch-Reliability	1,278,429	1,212,048
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	870,398	845,090
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,211,427	1,176,516
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	579,429	636,145
90	(561.6) Transmission Service Studies		-718
91	(561.7) Generation Interconnection Studies	560,445	842,803
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	124,237	271,886
94	(563) Overhead Lines Expenses	108,406	71,660
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	4,813,296	7,561,801
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	15,498,247	17,489,968
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,525,000	1,330,764
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	47,237	71,151
104	(569.2) Maintenance of Computer Software	104,143	256,180
105	(569.3) Maintenance of Communication Equipment	65,239	55,735
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	7,678,463	8,615,169
108	(571) Maintenance of Overhead Lines	8,002,902	6,931,513
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	3,060,310	2,878,250
111	TOTAL Maintenance (Total of lines 101 thru 110)	20,483,294	20,138,762
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	35,981,541	37,628,730

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	22,157,709	21,206,569
135	(581) Load Dispatching	4,293,993	4,495,958
136	(582) Station Expenses	43,503	60,925
137	(583) Overhead Line Expenses	5,162,020	5,339,867
138	(584) Underground Line Expenses	2,105,076	2,250,861
139	(585) Street Lighting and Signal System Expenses	5,858,665	5,151,091
140	(586) Meter Expenses	9,329,203	8,862,762
141	(587) Customer Installations Expenses	1,277,442	1,391,200
142	(588) Miscellaneous Expenses	16,447,032	22,181,469
143	(589) Rents	631,393	645,555
144	TOTAL Operation (Enter Total of lines 134 thru 143)	67,306,036	71,586,257
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,685,497	2,506,866
147	(591) Maintenance of Structures	30,585	41,759
148	(592) Maintenance of Station Equipment	3,967,733	4,884,509
149	(593) Maintenance of Overhead Lines	31,553,385	29,817,899
150	(594) Maintenance of Underground Lines	8,708,040	8,086,742
151	(595) Maintenance of Line Transformers	2,485,769	80,612
152	(596) Maintenance of Street Lighting and Signal Systems	148,612	10,324
153	(597) Maintenance of Meters	789,973	884,396
154	(598) Maintenance of Miscellaneous Distribution Plant	13,840,595	25,461,009
155	TOTAL Maintenance (Total of lines 146 thru 154)	64,210,189	71,774,116
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	131,516,225	143,360,373
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,402,030	2,446,902
160	(902) Meter Reading Expenses	2,573,610	2,813,895
161	(903) Customer Records and Collection Expenses	29,710,619	29,315,659
162	(904) Uncollectible Accounts	18,605,707	13,548,619
163	(905) Miscellaneous Customer Accounts Expenses	1,541,367	1,818,192
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	54,833,333	49,943,267

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		20,333
168	(908) Customer Assistance Expenses	71,189,081	63,648,779
169	(909) Informational and Instructional Expenses	5,696,057	7,682,131
170	(910) Miscellaneous Customer Service and Informational Expenses	4,266	142,758
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	76,889,404	71,494,001
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,185,806	1,570,920
176	(913) Advertising Expenses	19,558	160,480
177	(916) Miscellaneous Sales Expenses	47,306	43,213
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,252,670	1,774,613
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	55,074,343	59,234,000
182	(921) Office Supplies and Expenses	22,175,062	26,564,567
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	34,358,411	35,046,074
185	(924) Property Insurance	12,144,902	75,934,878
186	(925) Injuries and Damages	9,338,915	8,882,337
187	(926) Employee Pensions and Benefits	63,892,111	48,155,205
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	484,359	381,186
190	(929) (Less) Duplicate Charges-Cr.	1,635,541	1,513,272
191	(930.1) General Advertising Expenses	1,138,187	2,089,820
192	(930.2) Miscellaneous General Expenses	7,842,368	1,803,238
193	(931) Rents	7,157,195	8,565,952
194	TOTAL Operation (Enter Total of lines 181 thru 193)	211,970,312	265,143,985
195	Maintenance		
196	(935) Maintenance of General Plant	2,781,644	-9,046,307
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	214,751,956	256,097,678
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,473,512,611	3,721,321,145

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PURCHASED POWER:					
2	SOUTHEASTERN POWER ADM	OS	FERC NO. 65	N/A	N/A	N/A
3	AUBURNDALE POWER PARTNERS (1)	OS	COG	131	145	140
4	AUBURNDALE POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
5	CENTRAL POWER & LIME (1)	OS	COG	N/A	N/A	N/A
6	CENTRAL POWER & LIME (1)	AD	COG	N/A	N/A	N/A
7	CITRUS WORLD (1)	OS	COG	N/A	N/A	N/A
8	CITRUS WORLD (1)	AD	COG	N/A	N/A	N/A
9	LAKE COUNTY (1)	OS	COG	10	12	10
10	LAKE COUNTY (1)	AD	COG	N/A	N/A	N/A
11	LAKE COGEN LIMITED (1)	OS	COG	115	121	113
12	LAKE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
13	DADE COUNTY (1)	OS	COG	34	48	32
14	DADE COUNTY (1)	AD	COG	N/A	N/A	N/A
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
							1
19,176				963,101		963,101	2
629,402			43,270,202	30,504,537		73,774,739	3
					-69,154	-69,154	4
419,490				14,199,913		14,199,913	5
8					278	278	6
614				21,698		21,698	7
17					736	736	8
80,338			7,252,200	2,387,649		9,639,849	9
					-1,026	-1,026	10
478,563			36,727,807	24,872,216		61,600,023	11
					-63,495	-63,495	12
285,133			13,797,840	12,579,493		26,377,333	13
					-90,255	-90,255	14
8,706,056			363,760,004	377,759,595	-1,162,867	740,356,732	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	ORANGE COGEN LIMITED (1)	OS	COG	70	104	84
2	ORANGE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
3	ORLANDO COGEN LIMITED (1)	OS	COG	78	125	107
4	ORLANDO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
5	PASCO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
6	PASCO COUNTY (1)	OS	COG	21	25	20
7	PASCO COUNTY (1)	AD	COG	N/A	N/A	N/A
8	PCS PHOSPHATE (1)	OS	COG	N/A	N/A	N/A
9	PCS PHOSPHATE (1)	AD	COG	N/A	N/A	N/A
10	PINELLAS COUNTY (1)	OS	COG	38	62	29
11	PINELLAS COUNTY (1)	AD	COG	N/A	N/A	N/A
12	POLK POWER PARTNERS (1)	OS	COG	108	125	98
13	POLK POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
14	RIDGE GENERATING STATION (1)	OS	COG	32	41	31
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
277,471			31,621,358	11,598,201		43,219,559	1
					96,691	96,691	2
699,049			28,298,087	35,524,550		63,822,637	3
					-59,090	-59,090	4
					-85,337	-85,337	5
167,861			13,082,400	4,968,359		18,050,759	6
					-1,941	-1,941	7
1,153				36,995		36,995	8
							9
304,341			28,085,290	9,035,305		37,120,595	10
					-790,991	-790,991	11
415,698			54,478,493	14,388,424		68,866,917	12
					-70,176	-70,176	13
187,475			9,122,129	10,193,703		19,315,832	14
8,706,056			363,760,004	377,759,595	-1,162,867	740,356,732	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	RIDGE GENERATING STATION (1)	AD	COG	N/A	N/A	N/A
2	SI GROUP ENERGY	OS	COG	N/A	N/A	N/A
3	SI GROUP ENERGY	AD	COG	N/A	N/A	N/A
4	INTERCHANGE POWER:					
5	CHATTAHOOCHEE, CITY OF	OS				
6	CHATTAHOOCHEE, CITY OF	AD				
7	COBB ELECTRIC MEMBERSHIP CORP.	OS				
8	CAROLINA PWR. & LIGHT CO.	OS	FERC NO. 5			
9	CAROLINA PWR. & LIGHT CO.	AD	FERC NO. 5			
10	CALPINE ENERGY SVCS., L.P.	OS	FERC NO. 170			
11	CARGILL-ALLIANT, LLC	OS				
12	CONSTELLATION ENERGY	OS				
13	DUKE ENERGY TRADING	OS				
14	DUKE ENERGY TRADING	AD				
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
					33,268	33,268	1
				159,053		159,053	2
4,486					-35,468	-35,468	3
							4
			137,769			137,769	5
					8,064	8,064	6
				4,258,492		4,258,492	7
91,738				310		310	8
					331	331	9
				996,513		996,513	10
24,068				775,679		775,679	11
12,941				3,750,719		3,750,719	12
87,872				37,344		37,344	13
					-399	-399	14
8,706,056			363,760,004	377,759,595	-1,162,867	740,356,732	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	FLORIDA POWER & LIGHT CO.	OS	FERC NO. 81			
2	FLORIDA POWER & LIGHT CO.	AD	FERC NO. 81			
3	GEORGIA POWER	OS				
4	GEORGIA TRANSMISSION CORP	OS				
5	HARDEE POWER PARTNERS LTD	OS				
6	JACKSONVILLE ELECTRIC AUTHORITY	OS	FERC NO. 91			
7	JP MORGAN VENTURES	OS				
8	LAKELAND, CITY OF	OS	FERC NO. 92			
9	NEW HOPE POWER PARTNERSHIP	OS				
10	NEW SMYRNA BEACH, CITY OF	OS	FERC NO. 104			
11	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86			
12	PJM INTERCONNECTION, LLC	OS				
13	PJM INTERCONNECTION, LLC	AD				
14	RAINBOW ENERGY MARKETING CORP	OS				
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
41,695				2,084,954		2,084,954	1
					-6	-6	2
2,283				524,770		524,770	3
				6,710		6,710	4
151				7,149		7,149	5
				1,908,558		1,908,558	6
5,332				302,302		302,302	7
160				36,000		36,000	8
225				9,360		9,360	9
				-153,799		-153,799	10
40,888				3,311,558		3,311,558	11
500				22,720		22,720	12
					30,342	30,342	13
160				10,520		10,520	14
8,706,056			363,760,004	377,759,595	-1,162,867	740,356,732	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	REEDY CREEK UTILITIES	OS	FERC NO. 119			
2	RELIANT ENERGY SERVICES INC.	OS	FERC NO. 167			
3	RELIANT ENERGY FLORIDA	OS				
4	RELIANT ENERGY FLORIDA	AD				
5	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128			
6	SHADY HILLS POWER COMPANY	OS				
7	SHADY HILLS POWER COMPANY	AD				
8	SOUTHERN COMPANY SERVICES INC.	OS	FERC NO. 111			
9	SOUTHERN COMPANY SERVICES, INC	AD	FERC NO. 111			
10	TALLAHASSEE, CITY OF	OS	FERC NO. 122			
11	THE ENERGY AUTHORITY	OS	FERC NO. 175			
12	TAMPA ELECTRIC CO.	OS	FERC NO. 80			
13	TAMPA ELECTRIC CO.	AD	FERC NO. 80			
14	CONOCO PHILLIPS	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
10,610				745,306		745,306	1
12,640				974,284		974,284	2
5,089			1,405,104	603,593		2,008,697	3
74					7,896	7,896	4
36,573				1,503,847		1,503,847	5
998,120			26,884,429	96,099,701		122,984,130	6
					-48,342	-48,342	7
3,177,793			61,679,692	73,869,255		135,548,947	8
					-24,791	-24,791	9
				161,528		161,528	10
75,806				4,290,716		4,290,716	11
107,185			7,917,204	9,980,632		17,897,836	12
					-2	-2	13
863				43,539		43,539	14
8,706,056			363,760,004	377,759,595	-1,162,867	740,356,732	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	INADVERTENT INTERCHANGE (NET)	OS				
2	MUNICIPAL ELECT AUTHORTITY OF GA	OS				
3	WESTAR ENERGY	OS				
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
-109							1
				17,392		17,392	2
				146,746		146,746	3
3,124							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
8,706,056			363,760,004	377,759,595	-1,162,867	740,356,732	

Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: a

Schedule Page: 326 Line No.: 4 Column: l
OUT OF PERIOD ADJUSTMENT: AUBURNDALE POWER PARTNERS - ENERGY ($69,154).

Schedule Page: 326 Line No.: 6 Column: l
OUT OF PERIOD ADJUSTMENT: CENTRAL POWER & LIME - ENERGY $278.

Schedule Page: 326 Line No.: 8 Column: l
OUT OF PERIOD ADJUSTMENT: CITRUS WORLD - ENERGY $736.

Schedule Page: 326 Line No.: 10 Column: l
OUT OF PERIOD ADJUSTMENT: LAKE COUNTY - ENERGY ($1,026).

Schedule Page: 326 Line No.: 12 Column: l
OUT OF PERIOD ADJUSTMENT: LAKE COGEN LIMITED - ENERGY ($63,495).

Schedule Page: 326 Line No.: 14 Column: l
OUT OF PERIOD ADJUSTMENT: DADE COUNTY - ENERGY ($127,092) AND CAPACITY $36,837.

Schedule Page: 326.1 Line No.: 2 Column: l
OUT OF PERIOD ADJUSTMENT: ORANGE COGEN LIMITED - ENERGY $96,882 AND CAPACITY ($191).

Schedule Page: 326.1 Line No.: 4 Column: l
OUT OF PERIOD ADJUSTMENT: ORLANDO COGEN LIMITED - ENERGY ($59,090).

Schedule Page: 326.1 Line No.: 5 Column: l
OUT OF PERIOD ADJUSTMENT: PASCO COGEN LIMITED - ENERGY ($70,628) AND CAPACITY ($14,709).

Schedule Page: 326.1 Line No.: 7 Column: l
OUT OF PERIOD ADJUSTMENT: PASCO COUNTY - ENERGY ($1,941).

Schedule Page: 326.1 Line No.: 11 Column: l
OUT OF PERIOD ADJUSTMENT: PINELLAS COUNTY - ENERGY ($2,804) AND CAPACITY ($788,187).

Schedule Page: 326.1 Line No.: 13 Column: l
OUT OF PERIOD ADJUSTMENT: POLK POWER PARTNERS - ENERGY ($70,176).

Schedule Page: 326.2 Line No.: 1 Column: l
OUT OF PERIOD ADJUSTMENT: RIDGE GENERATING STATION - ENERGY $27,112 AND CAPACITY $6,156.

Schedule Page: 326.2 Line No.: 3 Column: l
OUT OF PERIOD ADJUSTMENT: SI GROUP ENERGY - ENERGY ($35,468).

Schedule Page: 326.2 Line No.: 4 Column: a

Schedule Page: 326.2 Line No.: 6 Column: a
OUT-OF-PERIOD ADJUSTMENT - CITY OF CHATTAHOOCHEE - CAPACITY $8064.

Schedule Page: 326.2 Line No.: 9 Column: a
OUT-OF-PERIOD ADJUSTMENTS - CAROLINA PWR. & LIGHT CO. - ENERGY $331.

Schedule Page: 326.2 Line No.: 14 Column: a
OUT-OF-PERIOD ADJUSTMENT - DUKE ENERGY TRADING - ENERGY ($399).

Schedule Page: 326.3 Line No.: 2 Column: a
OUT-OF-PEROD ADJUSTMENT - FLORIDA POWER & LIGHT CO. - ENERGY ($5,68).

Schedule Page: 326.3 Line No.: 13 Column: a
OUT-OF-PERIOD ADJUSTMENT - PJM INTERCONNECTION, LLC - ENERGY $30,343.

Schedule Page: 326.4 Line No.: 4 Column: a
OUT-OF-PERIOD ADJUSTMENT - RELIANT ENERGY FLORIDA - MW 74 ENERGY $7,425 AND CAPACITY $470.

Schedule Page: 326.4 Line No.: 7 Column: a
OUT-OF-PERIOD ADJUSTMENT - SHADY HILLS POWER COMPANY - ENERGY ($48,342).

Schedule Page: 326.4 Line No.: 9 Column: a
OUT-OF-PERIOD ADJUSTMENT - SOUTHERN COMPANY SERVICES INC. - ENERGY ($24,880) AND CAPACITY $90.

Schedule Page: 326.4 Line No.: 13 Column: a
OUT-OF-PERIOD ADJUSTMENT - TAMPA ELECTRIC CO. - ENERGY ($2).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	CIty of Alachua-Gainesville	Progress Energy Florida	City of Alachua	LFP
2	City of Bartow	Progress Energy FLorida	City of Bartow	FNO
3	Calpine Energy Services	Various	Various	NF
4	Cargill Power Markets, LLC.	Various	Various	NF
5	Central Power and Lime	Various	Various	NF
6	Cobb Electric Membership	Various	Various	NF
7	Conoco, Inc.	Various	Various	NF
8	Eagle Energy Partners	Various	Various	NF
9	Florida Municipal Power Authorty	Various	Various	NF
10	Florida Power & Light Co.	Various	Various	NF
11	Fortis Energy Marketing Trading	Various	Various	NF
12	Gainesville Regional Utilities	Progress Energy Florida	Gainesville Regional	LFP
13	Georgia Power Company	Progress Energy FLorida	Georgia Power Co.	OLF
14	City of Homestead	Progress Energy Florida	City of Homestead	LFP
15	City of Homestead	Progress Energy Florida	City of Homestead	NF
16	City of Homestead	Progress Energy Florida	City of Homestead	SFP
17	Kissimmee Utility Auth	Progress Energy Florida	Kissimmee Utility Auth	LFP
18	Lakeland Utilites	Various	Various	NF
19	City of Mt. Dora	Progress Energy Florida	City of Mt. Dora	FNO
20	JP Morgan Ventures	Various	Various	NF
21	Utilities Comm of New Smyrna Beach	Progress Energy Florida	Utilites Comm of New Smyrna Beach	LFP
22	Utilities Comm of New Smyrna Beach	Progress Energy Florida	Utilities comm of New Smyrna Beah	LFP
23	Utilities Comm of New Smyrna Beach	Various`	Various	NF
24	Oglethorpe Power Corp	Various	Various	NF
25	Orange Cogen LP	Orange Cogen LP	Tampa Electric Company	LFP
26	Orlando Utilities Commission	Progress Energy Florida	Orlando Utilities Commission	LFP
27	Orlando Utilities Commission	Various	Various	NF
28	City of Quincy	Progress Energy Florida	City of Quincy	FNO
29	Rainbow Energy Marketing Corp.	Various	Various	NF
30	Reedy Creek Improvement Dist.	Various	Various	NF
31	Reliant Energy Services	Reliant Energy Svcs	Florida Power & Light	LFP
32	Reliant Energy Services	Various	Various	NF
33	Seminole Electric Coop	Progress Energy Florida	Seminole Electric Coop	SFP
34	Seminole Electric Coop	Various	Various	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
T6/72	Crystal River Sub	Gainesville Regional	1		4,673	1
T6/136	Various	City of Bartow		691	691	2
T6/106	Various	Various		9,551	9,354	3
T6/230C	Various	Various		40,231	39,400	4
T6/141	Various	Various				5
T6/114	Various	Various		3,474	3,399	6
T6/232C	Various	Various				7
T6/257C	Various	Various		979	960	8
T6/31	Various	Various	19	430	422	9
T6/7C	Various	Various		7,498	7,341	10
T6/285C	Various	Various				11
T6/73	Crystal River Sub	Gainesville Regional	12	89,094	84,437	12
FERC No. 105	Intercession City Sb	Ga Power Company	146			13
T6/130	Various	FL Power & Light	30	196,807	192,735	14
T6/52	Various	FL Power & Light				15
T6/53	Various	FL Power & Light				16
T6/74	Crystal River Sub	Kissimmee Utility	6	41,275	41,275	17
T6/56	Various	Various		5,555	5,422	18
T6/133	Various	City of Mt. Dora		231	231	19
T6/132	Various	Various		23,074	22,594	20
T6/75	Crystal River Sub	New Smyrna Beach	5	34,023	34,023	21
T6/138	Smyrna Sub	New Smyrna Beach	23	86,540	84,750	22
T6/12	Various	Various		1,586	1,568	23
T6/187C	Various	Various				24
T6/77	Orange Sub	Tampa Electric Co	23	72,966	72,966	25
T6/76	Crystal River Sub	Orlando Utilities Cm	13	97,587	97,587	26
T6/10	Various	Various		1,670	1,635	27
T6/137	Various	City of Quincy		250	250	28
T6/35C	Various	Various		7,142	7,013	29
T6/14	Various	Various		9,571	9,374	30
T6/92	Hudson Sub	FL Power & Light				31
T6/3	Various	Various				32
T6/24	Progress Energy FL	Seminole Elec Coop	15			33
T6/23	Various	Various		5,247	5,155	34
			651	1,849,280	1,809,166	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
13,798			13,798	1
1,494,526			1,494,526	2
34,342			34,342	3
145,579			145,579	4
36,685			36,685	5
22,231			22,231	6
1,298			1,298	7
2,511			2,511	8
2,237			2,237	9
30,864			30,864	10
-3			-3	11
275,185			275,185	12
1,038,015			1,038,015	13
705,409			705,409	14
				15
				16
131,980			131,980	17
23,728			23,728	18
495,676			495,676	19
94,020			94,020	20
114,041			114,041	21
517,775			517,775	22
14,387			14,387	23
5,136			5,136	24
529,930			529,930	25
287,512			287,512	26
15,624			15,624	27
340,316			340,316	28
-3,230			-3,230	29
82,307			82,307	30
-17			-17	31
				32
266,605			266,605	33
26,280			26,280	34
56,155,438	0	0	56,155,438	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Southern Company of Florida	Various	Various	NF
2	City of Tallahassee	Progress Energy Floirda	City of Tallahassee	LFP
3	City of Tallahassee	City of Tallahassee	City of Tallahassee	LFP
4	City of Tallahassee	Various	Various	NF
5	Tampa Electric Company	Progress Enegy Florida	Tampa Electric Company	LFP
6	Tampa Electric Company	Various	Various	NF
7	Tampa Electric Company	Tampa Electric Company	Cities of Ft. Meade & Wachula	FNO
8	Tampa Electric Company	Progress Energy Floirda	Tampa Electric Company	SFP
9	Tennessee Valley Authoritty	Various	Various	NF
10	The Energy Authority	Progress Energy Florida	Gainesville Regional Utililites	LFP
11	The Energy Authority	Progress Energy Florida	Gainesville Regional Utilities	LFP
12	The Energy Authority	Various	Various	SFP
13	The Energy Authority	Various	Various	SFP
14	The Energy Authority	Various	Various	NF
15	City of Williston	Progress Energy Florida	City of Williston	FNO
16	City of Winter Park	Progress Energy Florida	City of Winter Park	FNO
17	Constallation Energy	Various	Various	NF
18	FPC Power Marketing & CPL	Various	Various	NF
19	The Energy Authourity	Progress Energy Florida, Inc	Gainesville Regional Utilities	NF
20	Seminole Elec Coop, Inc.			FNO
21	Florida Municipal Power Auth-OS	Various	Various	OS
22	Reedy Creek-OS	Various	Various	OS
23	Seminole Electric Cooperative Inc.	Various	Various	OS
24	Southeastern Power Admin-OS	Various	Various	OS
25	Constellation Power Source	Various	Various	NF
26	Alabama Electric Coop	Various	Various	OS
27	City of New Symrna	Various	Various	NF
28	Pa-NJ-Maryland Int (PJM)	Various	Various	NF
29	Tennessee Valley Authority	Various	Various	NF
30	Carolina Power & Light	Various	Various	NF
31	Duke Power			NF
32				
33				
34				
	TOTAL			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
						1
T6/29C	Various	Various		100,581	98,674	2
T6/96	Progress Energy FL	City of Tallahassee	11	20,657	20,229	3
T6/97	Jackson Bluff Sub	City of Tallahassee	11	842	829	4
T6/19	Various	Various		75,813	74,249	5
T6/134	Progress Energy FL	Tampa Electric Co.	158	21,312	20,864	6
T6/160C	Various	Various				7
T6/98	Tampa Electric Co	Ft. Meade & Wachula		148,502	145,424	8
T6/25	Progress Energy FL	Tampa Electric Co.	100			9
T6/21C	Various	Various		24,943	24,412	10
T6/140	Progress Energy FL	Gainesville Regional	3	240,616	235,635	11
T6/139	Progress Energy FL	Gainesville Regionas	75			12
T6/142	Various	Various		7,081	6,933	13
T6/62	Various	Various		80,510	79,003	14
T6/68C	Various	Various		76	76	15
T6/125	Various	City of Winter Park		989	989	16
T6/124	Various	City of Winter Park		42	42	17
T6/63C	Various	Various		175,855	172,219	18
T6/76C	Various	Various				19
T6	Progress Energy FL	Gainesville Regionas		7,249	7,249	20
T6/143	Various	Seminole Elec Coop				21
T6/31	Various	Various				22
T6	Various	Various				23
T6	Various	Various		208,740	195,084	24
T6	Various	Various				25
T8	Various	Various				26
T6	Various	Various				27
T6	Various	Various				28
T6	Various	Various				29
T6/70	Various	Various				30
T8/76	Various	Various				31
T6	Various	Various				32
						33
						34
			651	1,849,280	1,809,166	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
7,355			7,355	1
268,767			268,767	2
253,511			253,511	3
4,872			4,872	4
3,909,568			3,909,568	5
137,838			137,838	6
317,353			317,353	7
1,540,493			1,540,493	8
3,628			3,628	9
206,163			206,163	10
1,810,850			1,810,850	11
				12
24,235			24,235	13
239,854			239,854	14
167,118			167,118	15
2,090,582			2,090,582	16
5,675			5,675	17
876,063			876,063	18
2,483			2,483	19
13,742,688			13,742,688	20
4,557,256			4,557,256	21
1,594,374			1,594,374	22
17,324,454			17,324,454	23
287,749			287,749	24
9,526			9,526	25
				26
				27
24,677			24,677	28
				29
1,999			1,999	30
1,560			1,560	31
				32
				33
				34
56,155,438	0	0	56,155,438	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	6,123,329
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	4,048
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	592,860
6	Inventory Adjustment	-191,560
7	Stores Burden Adjustment	578,473
8	Florida Sales Tax Audit	470,995
9	Stock Listing/Debt Rating Fees	94,437
10	Trustee Fees	26,000
11	Career Transition Costs	143,786
12	Accounting Adjustments	
13		
14		
15		
16		
17		
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45		
46	TOTAL	7,842,368

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			2,031,089		2,031,089
2	Steam Production Plant	57,293,564	2,211,364			59,504,928
3	Nuclear Production Plant	18,609,721	475,740			19,085,461
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	77,880,262				77,880,262
7	Transmission Plant	36,199,684				36,199,684
8	Distribution Plant	124,581,614				124,581,614
9	Regional Transmission and Market Operation					
10	General Plant	16,355,621	42,657	247,645		16,645,923
11	Common Plant-Electric					
12	TOTAL	330,920,466	2,729,761	2,278,734		335,928,961

B. Basis for Amortization Charges

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission Fee for				
2	Fiscal Year 2009	484,359		484,359	
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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15					
16					
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43					
44					
45					
46	TOTAL	484,359		484,359	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B. Electric, R, D & D Performed Externally:	
2	(1) Research Support to the Electrical	
3	Research Council or the Electric	
4	Power Research Institute	2009 Nuclear Power Program
5		
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
	480,542	930	480,542		4
					5
					6
					7
					8
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Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	77,217,463		
4	Transmission	11,341,566		
5	Regional Market			
6	Distribution	40,988,324		
7	Customer Accounts	20,386,944		
8	Customer Service and Informational	12,113,621		
9	Sales	818,585		
10	Administrative and General	55,645,200		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	218,511,703		
12	Maintenance			
13	Production	50,284,961		
14	Transmission	7,142,395		
15	Regional Market			
16	Distribution	20,477,955		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	77,905,311		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	127,502,424		
21	Transmission (Enter Total of lines 4 and 14)	18,483,961		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	61,466,279		
24	Customer Accounts (Transcribe from line 7)	20,386,944		
25	Customer Service and Informational (Transcribe from line 8)	12,113,621		
26	Sales (Transcribe from line 9)	818,585		
27	Administrative and General (Enter Total of lines 10 and 17)	55,645,200		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	296,417,014	3,955,257	300,372,271
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	296,417,014	3,955,257	300,372,271
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	107,336,370	9,582,813	116,919,183
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	107,336,370	9,582,813	116,919,183
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Exp Undistributed	8,265,343	-8,265,343	
79	Clearing Accounts	5,272,727	-5,272,727	
80	Misc Deferred Debits	202,169		202,169
81	All Other Accounts	2,111,537		2,111,537
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	15,851,776	-13,538,070	2,313,706
96	TOTAL SALARIES AND WAGES	419,605,160		419,605,160

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	904,928	MW	2,974	376,220		1,051,698
2	Reactive Supply and Voltage	904,928	MW	17,245	363,761		1,555,363
3	Regulation and Frequency Response				21,534		846,031
4	Energy Imbalance				1,137		33,982
5	Operating Reserve - Spinning				2,168		92,682
6	Operating Reserve - Supplement				2,168		90,021
7	Other						
8	Total (Lines 1 thru 7)	1,809,856		20,219	766,988		3,669,777

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: System Peak Load Page 400

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	13,459	22	800	9,305	247	405	3,402	100	
2	February	13,605	6	800	9,415	242	405	3,443	100	
3	March	10,074	3	800	6,813	182	430	2,549	100	
4	Total for Quarter 1	37,138			25,533	671	1,240	9,394	300	
5	April	8,992	30	1800	6,289	169	430	2,004	100	
6	May	11,025	11	1700	7,786	215	430	2,494	100	
7	June	12,724	22	1800	8,942	229	430	3,023	100	
8	Total for Quarter 2	32,741			23,017	613	1,290	7,521	300	
9	July	11,931	16	1700	8,405	204	459	2,763	100	
10	August	12,052	11	1700	8,448	215	431	2,858	100	
11	September	12,939	22	1500	7,587	2,183	406	2,663	100	
12	Total for Quarter 3	36,922			24,440	2,602	1,296	8,284	300	
13	October	13,395	9	1700	8,204	2,240	408	2,543		
14	November	9,443	1	1500	5,897	1,439	408	1,699		
15	December	11,325	29	900	6,462	2,098	408	2,357		
16	Total for Quarter 4	34,163			20,563	5,777	1,224	6,599		
17	Total Year to Date/Year	140,964			93,553	9,663	5,050	31,798	900	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	13,159,151
4	Nuclear	4,944,898
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	17,620,190
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	35,724,239
10	Purchases	8,706,056
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	1,849,280
17	Delivered	1,809,166
18	Net Transmission for Other (Line 16 minus line 17)	40,114
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	44,470,409

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	37,824,252
23	Requirements Sales for Resale (See instruction 4, page 311.)	3,696,172
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	345,217
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	154,717
27	Total Energy Losses	2,450,051
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	44,470,409

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK: Megawatts (See Instr. 4) (d)	MONTHLY PEAK: Day of Month (e)	MONTHLY PEAK: Hour (f)
29	January	3,616,509	18,761	11,201	22	800
30	February	3,183,010	8,276	11,319	6	800
31	March	3,180,887	34,212	7,834	3	800
32	April	3,161,885	31,280	6,825	30	1800
33	May	3,839,456	17,581	8,743	11	1700
34	June	4,405,009	27,219	10,254	22	1800
35	July	4,478,028	28,040	9,300	16	1600
36	August	4,522,012	24,053	9,598	11	1700
37	September	4,081,517	52,758	8,394	22	1500
38	October	3,882,997	63,636	8,953	9	1700
39	November	2,936,164	8,625	6,238	1	1500
40	December	3,181,234	30,774	7,158	29	900
41	TOTAL	44,468,708	345,215			

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Anclote* (b)			Plant Name: *Bartow* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1974			1958
4	Year Last Unit was Installed			1978			1963
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			1112.40			494.36
6	Net Peak Demand on Plant - MW (60 minutes)			1032			0
7	Plant Hours Connected to Load			13710			3883
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			1052			440
10	When Limited by Condenser Water			1011			426
11	Average Number of Employees			71			0
12	Net Generation, Exclusive of Plant Use - KWh			1590574000			196021000
13	Cost of Plant: Land and Land Rights			1798861			1746939
14	Structures and Improvements			37967291			1165815
15	Equipment Costs			256164569			19447571
16	Asset Retirement Costs			507681			2610937
17	Total Cost			296438402			24971262
18	Cost per KW of Installed Capacity (line 17/5) Including			266.4854			50.5123
19	Production Expenses: Oper, Supv, & Engr			1524507			64809
20	Fuel			168931014			20331452
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			754166			153120
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			-1222			7257
26	Misc Steam (or Nuclear) Power Expenses			4890597			786583
27	Rents			0			0
28	Allowances			4167683			488117
29	Maintenance Supervision and Engineering			869055			124073
30	Maintenance of Structures			1008193			47087
31	Maintenance of Boiler (or reactor) Plant			4034734			126284
32	Maintenance of Electric Plant			1180910			27375
33	Maintenance of Misc Steam (or Nuclear) Plant			1712261			519198
34	Total Production Expenses			189071898			22675355
35	Expenses per Net KWh			0.1189			0.1157
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas		Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	BBL	MCF		BBL	MCF	
38	Quantity (Units) of Fuel Burned	1449392	9786030	0	340506	4247	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	155251	1014	0	156176	785	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	60.800	8.088	0.000	50.751	0.000	0.000
41	Average Cost of Fuel per Unit Burned	62.546	7.980	0.000	59.918	7.327	0.000
42	Average Cost of Fuel Burned per Million BTU	9.592	7.869	0.000	9.135	9.333	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.118	0.000	0.000	0.098	0.000
44	Average BTU per KWh Net Generation	0.000	12272.000	0.000	0.000	10464.000	0.000

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Crystal River South* (d)			Plant Name: *Crystal River North* (e)			Plant Name: *Crystal River* (f)			Line No.
								Nuclear	1
		Steam			Steam			Conventional	2
		Conventional			Conventional			1977	3
		1966			1982			1977	4
		1969			1984			890.46	5
		964.35			1478.52			869	6
		872			1420			6296	7
		16373			13342			0	8
		0			0			877	9
		874			1441			860	10
		869			1398			649	11
		93			393			4944898000	12
		4402749000			6735075000			10555395	13
		2188617			0			238000445	14
		77099418			261564257			627624558	15
		400768252			1686401158			18697978	16
		4923474			0			894878376	17
		484979761			1947965415			1004.9619	18
		502.9084			1317.5104			15147165	19
		2217957			4584564			26360191	20
		195424703			292515922			5519110	21
		0			0			10557228	22
		2028985			5065299			0	23
		0			0			0	24
		0			139			12574	25
		1333			1884			44023473	26
		3179795			3652650			0	27
		0			0			0	28
		14364340			21546510			0	29
		1482895			2624843			3027873	30
		829348			1098372			18402830	31
		4663731			11403249			4693195	32
		1033634			3167103			4565818	33
		7246065			5699971			132309457	34
		232472786			351360506			0.0268	35
		0.0528			0.0522				36
Oil	Coal		Oil	Coal		Oil	Nuclear		37
BBL	Tons		BBL	Tons		BBL	MMBTU		38
13832	1861519	0	70576	2887605	0	412	50890681	0	39
138289	12168	0	138553	11611	0	138061	0	0	40
111.384	103.262	0.000	113.770	97.758	0.000	82.911	0.000	0.000	41
119.596	103.562	0.000	115.087	96.366	0.000	0.000	0.486	0.000	42
20.591	4.255	0.000	19.777	4.150	0.000	0.000	0.486	0.000	43
0.000	0.044	0.000	0.000	0.041	0.000	0.000	0.005	0.000	44
0.000	10290.000	0.000	0.000	9956.000	0.000	0.000	10292.000	0.000	

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Suwannee* (b)			Plant Name: *Bayboro* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1953			1973
4	Year Last Unit was Installed			1956			1973
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			147.00			226.80
6	Net Peak Demand on Plant - MW (60 minutes)			132			204
7	Plant Hours Connected to Load			6955			1280
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			133			233
10	When Limited by Condenser Water			131			174
11	Average Number of Employees			31			4
12	Net Generation, Exclusive of Plant Use - KWh			234732000			43812000
13	Cost of Plant: Land and Land Rights			22059			1576410
14	Structures and Improvements			5145775			1692332
15	Equipment Costs			32815682			23385573
16	Asset Retirement Costs			1726484			0
17	Total Cost			39710000			26654315
18	Cost per KW of Installed Capacity (line 17/5) Including			270.1361			117.5234
19	Production Expenses: Oper, Supv, & Engr			505737			134075
20	Fuel			23778587			11673055
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			218291			155881
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			-1222			0
26	Misc Steam (or Nuclear) Power Expenses			1824481			284681
27	Rents			0			0
28	Allowances			671772			0
29	Maintenance Supervision and Engineering			41623			27342
30	Maintenance of Structures			252036			45029
31	Maintenance of Boiler (or reactor) Plant			567493			0
32	Maintenance of Electric Plant			336641			95428
33	Maintenance of Misc Steam (or Nuclear) Plant			887474			254425
34	Total Production Expenses			29082913			12669916
35	Expenses per Net KWh			0.1239			0.2892
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas		Oil		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	BBL	MCF		BBL		
38	Quantity (Units) of Fuel Burned	18154	2674054	0	101326	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	153713	1027	0	139267	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	68.673	9.575	0.000	107.047	0.000	0.000
41	Average Cost of Fuel per Unit Burned	73.629	8.382	0.000	114.930	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	11.405	8.163	0.000	19.649	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.099	0.000	0.266	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	12186.000	0.000	13528.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Debary* (d)			Plant Name: *Intercession City* (e)			Plant Name: *Suwannee* (f)			Line No.
Gas Turbine			Gas Turbine			Gas Turbine			1
Conventional			Conventional			Conventional			2
1975			1974			1980			3
1992			1992			1980			4
861.22			1310.20			183.60			5
712			1074			177			6
2998			11316			1966			7
0			0			0			8
781			1167			200			9
642			980			153			10
18			35			2			11
158570000			697306000			70175000			12
3140049			1565156			666505			13
9691422			15902692			1471200			14
146249506			241673177			29356343			15
0			0			0			16
159080977			259141025			31494048			17
184.7158			197.7874			171.5362			18
684430			592107			51904			19
21553500			90727779			9077286			20
0			0			0			21
348472			1070933			0			22
0			0			0			23
0			0			0			24
0			0			0			25
1301535			2008326			242811			26
0			0			0			27
278253			596173			215360			28
6733			115936			31574			29
72033			53583			22			30
0			0			0			31
1937881			2112089			860533			32
638704			589241			378343			33
26821541			97866167			10857833			34
0.1691			0.1403			0.1547			35
Oil	Gas		Oil	Gas		Oil	Gas		36
BBL	MCF		BBL	MCF		BBL	MCF		37
87647	1646995	0	118018	8264082	0	13172	902654	0	38
138149	1028	0	138017	1018	0	138938	1028	0	39
94.174	8.329	0.000	74.016	9.656	0.000	64.066	8.661	0.000	40
86.414	8.329	0.000	89.272	9.656	0.000	91.784	8.661	0.000	41
14.893	8.104	0.000	15.400	9.485	0.000	15.729	8.425	0.000	42
0.000	0.112	0.000	0.000	0.201	0.000	0.000	0.225	0.000	43
0.000	13883.000	0.000	0.000	13046.000	0.000	0.000	14319.000	0.000	44

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Bartow* (b)			Plant Name: *Turner* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Gas Turbine			Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1972			1970
4	Year Last Unit was Installed			1972			1974
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			222.80			180.98
6	Net Peak Demand on Plant - MW (60 minutes)			204			173
7	Plant Hours Connected to Load			1382			382
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			230			199
10	When Limited by Condenser Water			178			147
11	Average Number of Employees			2			0
12	Net Generation, Exclusive of Plant Use - KWh			49143000			20989000
13	Cost of Plant: Land and Land Rights			0			824781
14	Structures and Improvements			1076349			1432339
15	Equipment Costs			25556273			25524198
16	Asset Retirement Costs			0			0
17	Total Cost			26632622			27781318
18	Cost per KW of Installed Capacity (line 17/5) Including			119.5360			153.5049
19	Production Expenses: Oper, Supv, & Engr			281809			49362
20	Fuel			8994478			6467461
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			15840			105179
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			286046			285325
27	Rents			0			0
28	Allowances			39921			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			99340			30002
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			182317			159661
33	Maintenance of Misc Steam (or Nuclear) Plant			137861			184075
34	Total Production Expenses			10037612			7281065
35	Expenses per Net KWh			0.2043			0.3469
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas		Oil		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	BBL	MCF		BBL		
38	Quantity (Units) of Fuel Burned	46291	427064	0	54106	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138065	1025	0	138379	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	60.413	7.440	0.000	98.514	0.000	0.000
41	Average Cost of Fuel per Unit Burned	83.801	7.440	0.000	102.786	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	14.452	7.257	0.000	17.685	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.208	0.000	0.265	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	14371.000	0.000	14982.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Avon Park* (d)	Plant Name: *Higgins* (e)	Plant Name: *Tiger Bay* (f)	Line No.
Gas Turbine	Gas Turbine	Gas Turbine	1
Conventional	Conventional	Conventional	2
1968	1969	1995	3
1968	1971	1995	4
67.58	153.43	278.10	5
57	121	215	6
1232	1236	5552	7
0	0	0	8
66	128	224	9
48	114	205	10
0	4	15	11
28861000	32435000	1069180000	12
60423	184272	0	13
405755	754453	10463273	14
9683191	19059024	72614707	15
0	0	0	16
10149369	19997749	83077980	17
150.1830	130.3379	298.7342	18
40128	82617	573705	19
5236807	4585184	62564997	20
0	0	0	21
206133	211709	802099	22
0	0	0	23
0	0	0	24
0	0	0	25
277229	209442	931215	26
0	0	100794	27
176485	459278	209956	28
6411	5683	1423	29
10961	2438	169179	30
0	0	0	31
98224	521148	1761451	32
66551	259967	346099	33
6118929	6337466	67460918	34
0.2120	0.1954	0.0631	35

(d)			(e)			(f)			Line No.
									36
Oil	Gas		Oil	Gas		Gas			
BBL	MCF		BBL	MCF		MCF			37
16217	388532	0	5517	495812	0	7777796	0	0	38
138683	1027	0	137342	1026	0	1023	0	0	39
97.907	8.980	0.000	118.855	8.264	0.000	8.044	0.000	0.000	40
106.617	8.980	0.000	82.772	8.264	0.000	8.044	0.000	0.000	41
18.304	8.743	0.000	14.349	8.057	0.000	7.864	0.000	0.000	42
0.000	0.313	0.000	0.000	0.239	0.000	0.059	0.000	0.000	43
0.000	17099.000	0.000	0.000	16660.000	0.000	7441.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Rio Pinar* (b)			Plant Name: *Univ. of Florida* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1970			1994		
4	Year Last Unit was Installed	1970			1994		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	19.29			43.00		
6	Net Peak Demand on Plant - MW (60 minutes)	13			47		
7	Plant Hours Connected to Load	31			7255		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	13			47		
10	When Limited by Condenser Water	12			46		
11	Average Number of Employees	0			11		
12	Net Generation, Exclusive of Plant Use - KWh	389000			328278000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	115079			6551598		
15	Equipment Costs	3150394			37705650		
16	Asset Retirement Costs	0			0		
17	Total Cost	3265473			44257248		
18	Cost per KW of Installed Capacity (line 17/5) Including	169.2832			1029.2383		
19	Production Expenses: Oper, Supv, & Engr	4008			361855		
20	Fuel	123626			23980730		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	16463			749043		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	21956			73789		
27	Rents	0			0		
28	Allowances	0			182992		
29	Maintenance Supervision and Engineering	0			361275		
30	Maintenance of Structures	15224			160198		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	16424			132252		
33	Maintenance of Misc Steam (or Nuclear) Plant	12184			1126815		
34	Total Production Expenses	209885			27128949		
35	Expenses per Net KWh	0.5396			0.0826		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	BBL			MCF		
38	Quantity (Units) of Fuel Burned	1138	0	0	3300781	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138275	0	0	1026	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	116.654	0.000	0.000	7.253	0.000	0.000
41	Average Cost of Fuel per Unit Burned	100.542	0.000	0.000	7.247	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	17.312	0.000	0.000	7.064	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.294	0.000	0.000	0.073	0.000	0.000
44	Average BTU per KWh Net Generation	16990.000	0.000	0.000	10315.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

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Plant Name: *Hines Energy Complex* (d)	Plant Name: *Bartow* (e)	Plant Name: (f)	Line No.
			1
Gas Turbine	Gas Turbine		2
Conventional	Conventtional		3
1999			4
2007	2009	0.00	5
2265.75	1253.00	0	6
2056	1152	0	7
29450	22715	0	8
0	0	0	9
2199	1171	0	10
1912	1133	0	11
55	32	0	12
11261742000	3859308000	0	13
10012624	0	0	14
125089058	59167740	0	15
950652948	576551808	0	16
0	0	0	17
1085754630	635719548	0.0000	18
479.2032	507.3580	0	19
1784154	1265369	0	20
709617063	237912755	0	21
0	0	0	22
5494531	1982826	0	23
0	0	0	24
0	0	0	25
0	0	0	26
5183320	1775881	0	27
0	0	0	28
1134310	1004552	0	29
118793	359888	0	30
23749	41490	0	31
0	0	0	32
10818180	242505	0	33
4207941	701294	0	34
738382041	245286560	0	35
0.0656	0.0636	0.0000	36

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Oil	Gas		Oil	Gas					36
BBL	MCF		BBL	MCF					37
2153	79380300	0	37227	29935804	0	0	0	0	38
133656	1021	0	137241	1016	0	0	0	0	39
144.931	8.926	0.000	63.276	7.857	0.000	0.000	0.000	0.000	40
88.246	8.926	0.000	120.125	7.857	0.000	0.000	0.000	0.000	41
15.720	8.742	0.000	32.584	7.731	0.000	0.000	0.000	0.000	42
0.000	0.113	0.000	0.000	0.208	0.000	0.000	0.000	0.000	43
0.000	7197.000	0.000	0.000	14371.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000			0.0000		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0.0000	0.0000	0.0000	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000			0.0000		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0.0000			0.0000			0.0000			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			0.00			0.00
6	Net Peak Demand on Plant - MW (60 minutes)			0			0
7	Plant Hours Connected to Load			0			0
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			0			0
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			0			0
13	Cost of Plant: Land and Land Rights			0			0
14	Structures and Improvements			0			0
15	Equipment Costs			0			0
16	Asset Retirement Costs			0			0
17	Total Cost			0			0
18	Cost per KW of Installed Capacity (line 17/5) Including			0.0000			0.0000
19	Production Expenses: Oper, Supv, & Engr			0			0
20	Fuel			0			0
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			0			0
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			0			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			0			0
33	Maintenance of Misc Steam (or Nuclear) Plant			0			0
34	Total Production Expenses			0			0
35	Expenses per Net KWh			0.0000			0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0.0000			0.0000			0.0000			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000			0.0000		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0.0000			0.0000			0.0000			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: f

Crystal River plant contains on pressurized water reactor. The nuclear fuel assemblies in the reactor contains enriched uranium. The cost of power generated at the plant is accounted for in accordance with instructions as set forth in the FERC Classification of Accounts. The cost of nuclear fuel is amortized to fuel expense on a unit of production basis.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	500KV LINES	OVERHEAD						
2	CENTRAL FLORIDA	KATHLEEN	500.00	500.00	ST	44.22		1
3	CRYSTAL RIVER SUB	BROOKRIDGE	500.00	500.00	ST	34.40		1
4	BROOKRIDGE	LAKE TARPON	500.00	500.00	ST	37.63		1
5	CRYSTAL RIVER SUB	CENTRAL FLORIDA	500.00	500.00	ST	52.91		1
6								
7	230 KV LINES	UNDERGROUND						
8	BARTOW PLANT	NORTHEAST	230.00	230.00	HPOF	3.91		1
9	BARTOW PLANT	NORTHEAST	230.00	230.00	HPOF	3.98		1
10	BARTOW PLANT	NORTHEAST #6	230.00	230.00	XLPE	3.86		1
11								
12	230 KV LINES	OVERHEAD						
13	AVON PARK	FORT MEADE	230.00	230.00	ST	4.30		1
14					CP	2.14		
15					WH	19.86		
16					WP	0.94		
17					SP		1.22	
18	AVON PARK	FISHEATING CREEK	230.00	230.00	SP	9.02		1
19					CP	17.05		
20					WH	3.29		
21	ANCLOTE PLANT	LARGO	230.00	230.00	SH	15.29		1
22					SP	8.54		
23	ANCLOTE PLANT	EAST CLEARWATER	230.00	230.00	SH		15.30	1
24	ANCLOTE PLANT	SEVEN SPRINGS	230.00	230.00	SP	7.71		1
25	ALTAMONTE	WOODSMERE	230.00	230.00	WP	0.10		1
26					CP	0.11	0.56	
27					WH	10.99		
28					SP	0.82		
29	BARCOLA	CITY OF LAKELAND TIE	230.00	230.00	WH	18.68		1
30	BARCOLA	PEBBLEDALE	230.00	230.00	CP	3.86		1
31	BROOKRIDGE	BROOKRIDGE	230.00	230.00	WP	0.21		1
32	CRYSTAL RIVER	CURLEW	230.00	230.00	ST	77.88	78.14	1
33	CRYSTAL RIVER	CENTRAL FLORIDA	230.00	230.00	ST	53.36	39.59	1
34	CRYSTAL RIVER	FT. WHITE	230.00	230.00	WH	73.50		1
35	CENTRAL FLORIDA	SILVER SPRINGS	230.00	230.00	ST	29.01	5.15	2
36					TOTAL	4,405.13	538.80	90

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
2156 KCM ACSR	2,282,211	20,844,985	23,127,196					2
2335 KCM ACSR	12,767	12,289,151	12,301,918					3
2335 KCM ACSR								4
2335 KCM ACSR	9,840	8,806,860	8,816,700					5
								6
								7
2500 KCM CU		1,981,448	1,981,448					8
2500 KCM CU	258,670	2,109,689	2,368,359					9
5000 KCMIL CU	114,492	24,746,141	24,860,633					10
								11
								12
1081 KCM ACSR	85,476	4,043,784	4,129,260					13
954 KCM ACSR								14
954 KCM ACSR								15
954 KCM ACSR								16
954 KCM ACSR								17
1590 KCM ACSR	1,321,547	8,928,334	10,249,881					18
1590 KCM ACSR								19
1590 KCM ACSR								20
1590 KCM ACSR	521,102	5,915,691	6,436,793					21
1590 KCM ACSR								22
1590 KCM ACSR		723,363	723,363					23
2335 KCM ACAR	1,237,622	1,387,207	2,624,829					24
1590 KCM ACSR	43,803	1,865,391	1,909,194					25
1590 KCM ACSR								26
1590 KCM ACSR								27
1590 KCM ACSR								28
1590 KCM ACSR	133,007	3,354,926	3,487,933					29
1622 KCM		3,432,843	3,432,843					30
1590 KCM ACSR		100,451	100,451					31
1590 KCM ACSR	1,273,186	11,981,909	13,255,095					32
1590 KCM ACSR	775,227	7,069,041	7,844,268					33
954 KCM ACSR	219,431	9,110,663	9,330,094					34
1590 KCM ACSR	442,027	3,935,446	4,377,473					35
	88,358,382	953,604,820	1,041,963,202	108,405	8,002,902		8,111,307	36

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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	CENTRAL FLORIDA	SORRENTO	230.00	230.00	CP	14.65		1
2					SP	14.82		
3	CENTRAL FLORIDA	WINDERMERE	230.00	230.00	ST	69.76	46.61	1
4	CRAWFORDVILLE	PERRY	230.00	230.00	ST	12.09		1
5					WH	40.35		
6	CRAWFORDVILLE	PORT ST. JOE	230.00	230.00	WH	58.85		1
7					SP	2.65		
8					SH	0.65		
9	CRYSTAL RIVER EAST	SEVEN SPRINGS	230.00	230.00	ST		2.90	1
10	DEBARY	ALTAMONTE	230.00	230.00	SP	3.40	8.66	1
11					WH	3.06		
12					ST	0.56	3.23	
13					CP	0.49	0.32	
14	DEBARY	DELAND WEST	230.00	230.00	WH	7.15		1
15					WP	1.94		
16					CP	1.13		
17	DEBARY	NORTH LONGWOOD	230.00	230.00	WH	1.32		1
18					CH		2.70	
19					ST	3.36		
20					CP	0.42		
21					SP	9.15		
22	DEARMAN	SILVER SPRINGS NORTH	230.00	230.00	CP	4.27		1
23					ST		1.21	
24	DEBARY	WINTER SPRINGS	230.00	230.00	WH	3.23		1
25					SP	16.78		
26					ST	0.58		
27	FORT WHITE	SILVER SPRINGS	230.00	230.00	ST	1.46		1
28					SL	4.99		
29					CH	64.80		
30					CP	3.21		
31	40TH ST	PASADENA FSP	230.00	230.00	CP	0.19		1
32					SP	4.02		
33	FORT MEADE	VANDOLAH	230.00	230.00	SP	1.20		1
34					WH	21.05		
35					CP	1.80		
36					TOTAL	4,405.13	538.80	90

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

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8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590 KCM ACSR	1,621,137	10,444,336	12,065,473					1
1590 KCM ACSR								2
1590 KCM ACSR	1,128,343	7,647,603	8,775,946					3
954 KCM ACSR	1,207,871	4,162,848	5,370,719					4
954 KCM ACSR								5
954 KCM ACSR	626,506	7,607,087	8,233,593					6
954 KCM ACSR								7
954 KCM ACSR								8
1590 KCM ACSR	66,391	139,498	205,889					9
1590 KCM ACSR	284,757	2,287,498	2,572,255					10
1590 KCM ACSR								11
1590 KCM ACSR								12
1590/1431 KCM								13
1590 KCM ACSR	828,028	2,817,962	3,645,990					14
1590 KCM ACSR								15
1590 KCM ACSR								16
954 KCM ACSR	233,626	2,861,821	3,095,447					17
954 KCM ACSR								18
1590 KCM ACSR								19
1431 KCM ACSR								20
1590 KCM ACSR								21
954 KCM ACSR	195,181	1,628,711	1,823,892					22
954 KCM ACSR								23
1590 KCM ACSR	1,073,673	10,839,187	11,912,860					24
1590 KCM ACSR								25
1590 KCM ACSR								26
795 KCM ACSR	449,980	4,431,032	4,881,012					27
795 KCM ACSR								28
795 KCM ACSR								29
954 KCM ACSR								30
1590 KCM ACSR	2,510	2,050,089	2,052,599					31
1590 KCM ACSR								32
954 KCM ACSR	63,923	4,198,883	4,262,806					33
954 KCM ACSR								34
954 KCM ACSR								35
	88,358,382	953,604,820	1,041,963,202	108,405	8,002,902		8,111,307	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	FORT MEADE	WEST LAKE WALES	230.00	230.00	ST	3.07		1
2					WH	16.80		
3					SP	2.90		1
4	TIGER BAY	TECO	230.00	230.00	CP	0.10		1
5					ST	5.86		
6					WH	1.38		
7	HINES ENERGY	FORT MEADE	230.00	230.00	SP	6.45		1
8	HINES ENERGY	BARCOLA	230.00	230.00	SP	3.09		1
9	HINES ENERGY	BARCOLA (2ND CIRCUIT)	230.00	230.00	SP	3.09		1
10	HINES ENERGY	TIGER BAY	230.00	230.00	SP	0.64	3.51	
11	HINES PLANT	HINES	230.00	230.00	SP	1.64		
12	HINES	WEST LAKE WALES	230.00	230.00	SP	20.57		1
13	OLD SUB NORTH	NEW SUB NORTH	230.00	230.00	SP	0.22		1
14	INTERCESSION CITY	LAKE BRYAN 2ND CIRCUIT	230.00	230.00	SP	7.84		1
15	KATHLEEN	WEST LAKELAND	230.00	230.00	WH	14.50		1
16					CP	1.31		
17	KATHLEEN	ZEPHYRHILLS NORTH	230.00	230.00	WH	0.83		1
18					CP	8.70		
19					WP	1.35		
20	LARGO	PASADENA	230.00	230.00	ST		1.61	1
21					SP	13.13		
22	LAKE TARPON	CURLEW	230.00	230.00	ST	4.32		1
23	LAKE TARPON	HIGGINS	230.00	230.00	CP	2.57		1
24					SP	3.02		
25	LAKE TARPON	LARGO	230.00	230.00	SP	14.49		1
26					CP	2.90		
27	LAKE TARPON	SEVEN SPRINGS	230.00	230.00	ST	2.90		1
28	LAKE TARPON	TECO EXIST	230.00	230.00	ST	0.68		1
29					SP	0.81		
30	NORTHEAST	CURLEW	230.00	230.00	ST	16.95	12.78	1
31	NORTHEAST	40TH ST.	230.00	230.00	CP	0.16		1
32					SP	8.25		
33	NORTH LONGWOOD	PIEDMONT	230.00	230.00	SP	0.31	4.04	1
34					WH	6.16		
35	NORTH LONGWOOD	FP&L CO TIE	230.00	230.00	SP	4.04		1
36					TOTAL	4,405.13	538.80	90

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TRANSMISSION LINE STATISTICS (Continued)

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								1
1081 KCM ACAR	55,284	3,229,013	3,284,297					2
1081 KCM ACAR								3
1622 ACSS/TW								4
1590/1081 KCM	359,563	133,977	493,540					5
1081 KCM ACAR								6
1081/954 KCM								7
954 KCM ACSR		2,896,669	2,896,669					8
954 KCM ACSR		1,815,029	1,815,029					9
954 KCM ACSR		1,449,137	1,449,137					10
954 KCM ACSR		1,521,594	1,521,594					11
954 KCM ACSR		1,573,680	1,573,680					12
1622 ACSS/TW	10,149,381	35,815,448	45,964,829					13
2335 KCM ACAR		194,088	194,088					14
1622 ACSS TW		6,053,014	6,053,014					15
1590 KCM ACSR	507,363	3,393,713	3,901,076					16
1590 KCM ACSR								17
1590 KCM ACSR	275,097	3,486,259	3,761,356					18
1590 KCM ACSR								19
1590 KCM ACSR								20
1590 KCM ACSR	152,473	3,112,745	3,265,218					21
1590 KCM ACSR								22
1590 KCM ACSR		963,687	963,687					23
1590 KCM ACSR	15,699	1,499,798	1,515,497					24
1590 KCM ACSR								25
1590 KCM ACSR	412,563	8,586,465	8,999,028					26
1590 KCM ACSR								27
1590 KCM ACSR	189,338	694,404	883,742					28
1590 KCM ACSR		197,855	197,855					29
1590 KCM ACSR								30
1590 KCM ACSR	1,524,958	3,181,145	4,706,103					31
1590 KCA ACSR	288,076	8,237,630	8,525,706					32
1081 KCA ACAR								33
954 KCM ACSR	16,834	1,411,376	1,428,210					34
954 KCM ACSR								35
954 KCM ACSR	207,841	1,301,617	1,509,458					
	88,358,382	953,604,820	1,041,963,202	108,405	8,002,902		8,111,307	36

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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1					WH	2.77		
2	NORTH LONGWOOD	RIO PINAR	230.00	230.00	SP	0.58	3.94	1
3					CP	0.21		
4					AT	10.91		
5	NEWBERRY	WILCOX	230.00	230.00	SP	19.33		1
6	NORTHEAST	PINELLAS	230.00	230.00	CP	1.90		1
7	PIEDMONT	SORRENTO	230.00	230.00	SP	4.24		1
8					CP	6.45		
9					WH	4.79		
10	PIEDMONT	WOODSMERE	230.00	230.00	WH	6.72		1
11	PORT ST. JOE	GULF POWER	230.00	230.00	ST	33.99		1
12	RIO PINAR	OUC TIE	230.00	230.00	SP	0.52		1
13					AT	2.19		
14	SILVER SPRINGS	DELAND WEST	230.00	230.00	SL	39.93		1
15					SH	0.92		
16					SP	1.57		
17	SUWANNEE RIVER PLANT	FORT WHITE	230.00	230.00	ST	38.08		1
18	SKY LAKE	OUC TIE	230.00	230.00	CP	2.40		1
19					WP	2.22		
20	SUWANNEE	PERRY	230.00	230.00	ST	28.61		1
21	SUWANNEE PEAKERS	SUWANNEE	230.00	230.00	WH	0.63		1
22	SUWANNEE	GEORGIA GPC TIE	230.00	230.00	ST	18.36		1
23	TIGER BAY	FORT MEADE 2	230.00	230.00	SP	0.44	1.78	1
24	ULMERTON	LARGO	230.00	230.00	ST	5.05		1
25	VANDOLAH	SEMINOLE	230.00	230.00	SP	0.03		1
26	VANDOLAH	WHIDDEN	230.00	230.00	SP	14.40		1
27	WINDERMERE	INTERCESSION CITY	230.00	230.00	SP	15.07		1
28					CP	0.14		
29	WINDERMERE	WOODSMERE	230.00	230.00	WH	4.68		1
30					ST	1.82		
31	WEST LAKE WALES	INTERCESSION CITY	230.00	230.00	WH	19.59		1
32					SP	0.79		
33	WEST LAKE WALES	FP&L TIE	230.00	230.00	AT	58.48		1
34	WEST LAKE WALES	TECO TIE	230.00	230.00	AT	2.29		1
35	WINDERMERE	OUC TIE	230.00	230.00	WH	1.31		1
36					TOTAL	4,405.13	538.80	90

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 KCM ACSR								1
1590 KCM ACSR	420,736	1,828,798	2,249,534					2
954 KCM ACSR								3
954 KCM ACSR								4
1590 KCM ACSR	75,328	5,772,719	5,848,047					5
954 KCM ACSR		8,106	8,106					6
1590 KCM ACSR	574,273	5,229,617	5,803,890					7
1590 KCM ACSR								8
1590 KCM ACSR								9
954 KCM ACSR	15,605	587,317	602,922					10
795 KCM ACSR	71,747	2,339,842	2,411,589					11
954 KCM ACSR	100,034	2,111,864	2,211,898					12
954 KCM ACSR								13
1590 KCM ACSR	54,890	6,798,769	6,853,659					14
1590 KCM ACSR								15
1590 KCM ACSR								16
954 KCM ACSR	199,660	2,362,830	2,562,490					17
954 KCM ACSR	121,530	1,311,174	1,432,704					18
954 KCM ACSR								19
795 KCM ACSR	151,754	1,320,102	1,471,856					20
795 KCM ACSR		8,063	8,063					21
954 KCM ACSR	104,190	1,110,105	1,214,295					22
954 KCM ACSR		779,443	779,443					23
1590 KCM ACSR	601,048	1,780,364	2,381,412					24
954 ACSS TW		824,579	824,579					25
1622 ACSS TW		13,960,548	13,960,548					26
954 KCM ACSR	135,968	6,509,384	6,645,352					27
1622 ACSS/TW								28
1590 KCM ACSR	19,739	1,139,305	1,159,044					29
1590 KCM ACSR								30
954/1081 KCM	364,444	2,521,743	2,886,187					31
1622ACSS TW								32
954 KCM ACSR	595,327	5,510,858	6,106,185					33
954 KCM ACSR	17,342	232,082	249,424					34
954 KCM ACSR		513,323	513,323					35
	88,358,382	953,604,820	1,041,963,202	108,405	8,002,902		8,111,307	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	WOODSMERE	OUC TIE	230.00	230.00	ST		0.92	1
2								
3	OTHER TRANS. LINES	OVERHEAD 115 & 69				2,858.59	304.00	
4	OTHER TRANS. LINES	UNDERGROUND 115				47.29		
5								
6	Total Overhead Transmission	Line Expenses				4,349.27	538.17	79
7		(230, 115, 69 Kv)						
8	NEW LINES FOR 2008							
9	CENTRAL FLORIDA	BUSHNELL EAST	230.00	230.00	SP	8.28		1
10	LAKE BRYAN	WINDERMERE	230.00	230.00	SP	9.76		2
11	BARTOW PLANT (OH)	NORTHEAST (GENERATION	230.00	230.00	SP	1.53		1
12	NORTHEAST	NORTHEAST (SUB BUS)	230.00	230.00	SP	0.17		1
13								
14	NEW LINES FOR 2009							
15	BARTOW PLANT	NORTHEAST #7	230.00	230.00	XLPE	3.84		1
16	BARTOW PLANT	NORTHEAST #8	230.00	230.00	XLPE	3.92		1
17	DUNDEE	WEST LK WALES (DWL1)	230.00	230.00	SP	9.79		2
18	DUNDEE	WEST LK WALES (DWL2)	230.00	230.00	SP		0.63	1
19	AVON PARK	FORT MEADE - AF2	230.00	230.00	SP/ST	18.57		1
20								
21	BARTOW PLANT	NORTHEAST #9 DUCT BANK		230.00				
22	CENTRAL FLORIDA	TIFTON (LAND)						
23	NEWBERRY	MIDPOINT						
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,405.13	538.80	90

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 KCM ACSR		4,479	4,479					1
								2
	45,781,004	489,316,043	535,097,047					3
	88,132	12,219,085	12,307,217					4
				108,405	8,002,902		8,111,307	5
	80,159,555	850,592,763	930,752,318	108,405	8,002,902		8,111,307	6
								7
								8
1622 ACSS/TW	3,342,578	6,860,038	10,202,616					9
1622 ACSS/TW	1,360,155	8,688,107	10,048,262					10
1590 ACSR		1,851,186	1,851,186					11
1590 ACSR		507,482	507,482					12
								13
								14
5000 KCMIL CU	114,492	24,746,141	24,860,633					15
5000 KCMIL CU	114,492	24,746,141	24,860,633					16
2627 ACSS/TW	1,520,617	12,099,424	13,620,041					17
2627 ACSS/TW		3,771,505	3,771,505					18
1622 ACSS/TW		5,778,091	5,778,091					19
								20
	114,492	13,963,942	14,078,434					21
	1,046,211		1,046,211					22
	585,790		585,790					23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	88,358,382	953,604,820	1,041,963,202	108,405	8,002,902		8,111,307	36

Schedule Page: 422.4 Line No.: 35 Column: f

2008 transmission pole mile statistics have been updated to reflect current and prior year minor additions.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	BARTOW PLANT	NORTHEAST #6 (BNUG-6)	3.86	underground			
2	BARTOW PLANT	NORTHEAST #7 (BNUG-7)	3.84	underground			
3	BARTOW PLANT	NORTHEAST #8 (BNUG-8)	3.92	underground			
4	ASW-35	ASW-36 (ASW)	0.11	CP	12.00	1	1
5	FSP-30 - 51ST ST	51ST ST - FSP-30 (FSP)	0.36	SP	8.00	1	1
6	CFW-86	CAMP LAKE (CFW)	0.02	ST	5.00	2	2
7	NORTHEAST	40TH STREET (NF)	0.09	SP	14.00	2	2
8	DUNDEE	WEST LAKE WALES (DWL-1)	9.79	SP	8.00	2	2
9	DUNDEE	WEST LAKE WALES (DWL-2)	9.75	SP	8.00	1	1
10	WEST LAKE WALES	DUNDEE (WLIC)	-9.75	WH/SP	8.00	1	1
11	AF2-95-53	AF2-95-71 (AF2)	-1.32	CP	13.00	1	1
12	NORTHEAST	32ND STREET (NTH)	4.10	SP	10.00	1	1
13	BMF-120	FOUR CORNERS (BMF)	0.03	SP	24.00	1	1
14	ICP-74	POINCIANA NORTH (ICP)	0.80	CP	8.00	1	1
15	INVERNESS	BI-65 (BI)	0.47	CP	19.00	1	1
16	HB-98	INVERNESS (HB)		CP	14.00	2	2
17	OCOEE	WINTER GARDEN (WCE)	-0.01	CP	18.00	1	1
18	BWX-8B	BWX-51 (BWX)	1.94	CP	21.00	1	1
19	TC-103-11 GOAB	OLD TOWN (TC)	0.01	CP	11.00	1	1
20	SLE-6	SPRING LAKE (SLM)	0.04	CP	25.00	1	1
21	PSL-70	SPRING LAKE (PSL)	0.03	CP	21.00	1	1
22	ASL-130	SPRING LAKE (ASL)	0.03	CP	23.00	1	1
23	WCE-277	WCE-292 (WCE)	0.05	CP	16.00	1	1
24	WCE-300	WCE-314 (WCE)	0.09	CP	18.00	1	1
25	AVON PARK	FORT MEADE (AF2)	0.05	SP/ST	13.00	1	1
26	SLE-6	SPRING LAKE (SLE)	-0.08	CP	25.00	2	2
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		28.22		342.00	28	28

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
5000 kcmil	CU	Underground	230	114,492		24,746,141		24,860,633	1
5000 kcmil	CU	Underground	230	114,492		24,746,141		24,860,633	2
5000 kcmil	CU	Underground	230	114,492		24,746,141		24,860,633	3
1590	ACSR	VERTICAL	230		265,067	63,366		328,433	4
1590	ACSR	VERTICAL	230		1,093,139	85,849		1,178,988	5
1590	ACSR	VERTICAL	230		208,701	85,398		294,099	6
1622	ACSS/TW	VERTICAL	230		5,179,094	2,105,184	-540,638	6,743,640	7
2627	ACSS/TW	VERTICAL	230	1,520,617	9,947,236	2,152,188		13,620,041	8
2627	ACSS/TW	VERTICAL	230		1,619,317	2,152,188		3,771,505	9
954	ACSR	VERTICAL	230			134,035	-907,755	-773,720	10
4/0	ACSR	VERTICAL	115		43,463	2,981	-96,428	-49,984	11
1622	ACSW/TW	VERTICAL	115		1,164,203	1,076,410		2,240,613	12
795	AAC	DELTA	69		17,660	5,268		22,928	13
1272	ACSS/TW	VERTICAL	69	205,017	955,304	173,460		1,333,781	14
795	AAC	VERTICAL	115		49,743	298,962	-108,554	240,151	15
795	AAC	VERTICAL	69		1,175,922	556,414	-76,594	1,655,742	16
1272	ACSS/TW	VERTICAL	69	377,452	2,501,217	1,042,448	-142,564	3,778,553	17
2627	ACSS/TW	VERTICAL	115		1,980,086	403,793	-134,161	2,249,718	18
4/0	ACSR	VERTICAL	69		29,118	113,757		142,875	19
795	AAC	VERTICAL	69		7,731	102,041	-12,282	97,490	20
795	AAC	DELTA	69		97,867	11,293	-1,645	107,515	21
795	AAC	VERTICAL	69		158,689	21,703	-9,849	170,543	22
1272	ACSS/TW	VERTICAL	69		707,628	186,840	-162,105	732,363	23
1272	ACSS/TW	VERTICAL	69		390,395	74,744	-23,339	441,800	24
1622	ACSS/TW	VERTICAL	230		709,899	5,581,254	-513,062	5,778,091	25
795	AAC	VERTICAL	69		144,843	16,761	-13,422	148,182	26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				2,446,562	28,446,322	90,684,760	-2,742,398	118,835,246	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	32ND STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	40TH STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
3	51ST STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
4	51ST STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
5	ALDERMAN - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
6	ANCLOTE - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
7	BAYBORO - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	BAYVIEW - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
9	BAYWAY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
10	BELLEAIR - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	BROOKER CREEK - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
12	BROOKSVILLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	12.00
13	BROOKSVILLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	7.00
14	BROOKSVILLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	13.00
15	BROOKSVILLE ROCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	2.00	
16	BUSHNELL - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	CAMPS SECTION 7 MINE-COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
18	CENTER HILL - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	CENTRAL PLAZA - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
20	CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	CONSOLIDATED ROCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
22	CROSS BAYOU - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	CROSSROADS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	CURLEW - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
25	DENHAM - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	DISSTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
27	DISSTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
28	DUNEDIN - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	14.00
30	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	240.00	120.00	
31	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
32	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	ELFERS -COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
34	FLORAL CITY - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	FLORA-MAR - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
36	FLORIDA ROCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	66.00	3.00	
37	G.E. PINELLAS - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	GATEWAY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
39	HAMMOCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
40	HAMMOCK - COASTAL FLORDA REGION	DIST - UNATTENDED	67.00	4.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2					1
60	2					2
80	2					3
300	1					4
90	3					5
100	2					6
60	2					7
100	2					8
40	1					9
80	2					10
60	2					11
150	1					12
100	1					13
60	2					14
9	1	1				15
13	1					16
19	2	1				17
13	1	1				18
60	2					19
120	4					20
2	1	1				21
150	3					22
80	2					23
90	3					24
90	3					25
150	1					26
80	2					27
60	3					28
200	1					29
200	1					30
250	1					31
150	3					32
100	2					33
13	1					34
100	2					35
12	2	2				36
29	2					37
90	3					38
20	1					39
19	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HERNANDO AIRPORT - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	12.47	
2	HIGHLANDS - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	HIGGINS PLANT - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
4	KENNETH CITY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
5	LAND-O-LAKES - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
6	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
7	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
8	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	5.00
9	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	MAXIMO - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	NEW PORT RICHEY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
12	NORTHEAST - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	15.00
13	NORTHEAST - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
14	OAKHURST - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	PALM HARBOR - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
16	PALM HARBOR - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	PASADENA - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
18	PASADENA - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
19	PILSBURY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
20	PINELLAS WELL FIELD - COASTAL FLORIDA REGION	DIST - UNATTENDED	66.00	3.00	
21	PORT RICHEY WEST - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
22	SAFETY HARBOR - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	SEMINOLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
24	SEMINOLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	SEVEN SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
26	SEVEN SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
27	SIXTEENTH ST. - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
28	STARKEY ROAD - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	TANGERINE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	8.00
30	TARPON SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	
31	TARPON SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
32	TAYLOR AVE. - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	TRI-CITY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
34	TRILBY - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
35	ULMERTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	14.00
36	ULMERTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
37	ULMERTON WEST - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	VINOY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
39	WALSINGHAM - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	ZEPHYRHILLS - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
33	1					1
80	2					2
						3
60	2					4
30	1					5
200	1					6
200	1					7
200	1					8
100	2					9
150	3					10
60	2					11
400	2					12
100	2					13
90	3					14
250	1					15
60	2					16
250	1					17
80	2					18
100	2					19
5	1	1				20
90	3					21
80	2					22
250	1					23
100	2					24
60	2					25
750	3					26
80	2					27
80	2					28
60	2					29
150	1					30
100	2					31
80	2					32
60	2					33
9	1	1				34
450	2					35
100	2					36
80	2					37
100	2					38
100	2					39
60	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ZEPHYRHILLS NORTH - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
2	ZEPHYRHILLS NORTH - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	ZEPHYRHILLS NORTH - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
4	ZEPHYRHILLS NORTH - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
5					
6					
7	ALACHUA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	APALACHICOLA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	ARCHER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
10	ARCHER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
11	BEACON HILL - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	BEVILLES CORNER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
13	CARRABELLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	CARRABELLE BEACH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
15	CRAWFORDVILLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
16	CRAWFORDVILLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
17	CROSS CITY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	EAST POINT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	FOLEY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	FORT WHITE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
21	FORT WHITE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	4.00
22	FORT WHITE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
23	G.E. ALACHUA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	GAINESVILLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
25	GEORGIA PACIFIC - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	HIGH SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	HIGH SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	7.00	
28	HULL ROAD - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	INDIAN PASS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	JASPER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
31	JASPER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	JENNINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
33	LURAVILLE -NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	MADISON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
35	MONTICELLO - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	NEWBERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
37	NEWBERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
38	O'BRIEN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	OCCIDENTAL #1 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
40	OCCIDENTAL #1 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
250	1					1
60	2					2
250	1					3
30	2					4
						5
						6
13	1	1				7
13	1	1				8
150	1					9
16	2	2				10
60	2					11
22	1					12
13	1	1				13
10	1	1				14
100	1					15
13	1	1				16
13	1	1				17
13	1	1				18
40	2					19
100	1					20
75	1					21
6	1	1				22
20	1					23
30	1					24
10	1	1				25
9	1					26
13	1	1				27
19	2					28
5	1	1				29
60	1					30
13	1	1				31
2	1	1				32
9	1	1				33
40	2					34
40	2					35
100	1					36
13	1	1				37
6	1	1				38
50	1					39
25	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	OCCIDENTAL #2 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
2	OCCIDENTAL #3 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
3	OCCIDENTAL SWIFT CREEK#1-NORTHERN FLORIDA	DIST - UNATTENDED	115.00	4.00	
4	OCCIDENTAL SWIFT CREEK#2-NORTHERN FLORIDA	DIST - UNATTENDED	115.00	25.00	
5	OCCIDENTAL SWIFT CREEK#2-NORTHERN FLORIDA	DIST - UNATTENDED	115.00	13.00	
6	OCHLOCKONEE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	PERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
8	PERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	PERRY NORTH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	PORT ST. JOE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
11	PORT ST. JOE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	PORT ST. JOE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
13	RIVER JUNCTION - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
14	SHAMROCK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	12.00	4.00	
15	SOPCHOPPY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	ST. GEORGE ISLAND - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	ST. MARKS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	SUTTERS CREEK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	SUWANNEE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
20	TRENTON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	UNIVERSITY OF FLORIDA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	23.00	
22	WAUKEENAH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	WHITE SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	WILLISTON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	WILLISTON TOWN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
26					
27	ADAMS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	ALAFAYA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	ALTAMONTE SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
30	ALTAMONTE SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	APOPKA SOUTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	BARBERVILLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	BAY RIDGE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	BELLEVIEW - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	BEVERLY HILLS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
36	CASSADAGA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
37	CASSELBERRY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	CIRCLE SQUARE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	CITRUS HILL - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
40	CLARCONA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
40	2					1
13	1					2
60	3					3
20	1					4
30	1					5
20	1					6
250	2					7
40	2					8
20	1					9
100	1					10
20	1					11
200	2					12
19	1	1				13
2	1	1				14
9	1	1				15
20	1					16
13	1	1				17
19	2					18
20	1					19
13	1	1				20
90	3					21
9	1					22
2	1	1				23
13	1	1				24
9	1					25
						26
20	1					27
60	2					28
200	1					29
100	2					30
90	3					31
40	2					32
40	2					33
100	2					34
60	2					35
60	2					36
130	3					37
19	2					38
50	2					39
90	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CLERMONT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	COLEMAN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	CRYSTAL RIVER NORTH -NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
4	CRYSTAL RIVER SOUTH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
5	DELAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	PINE RIDGE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	DELAND EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	DELTONA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
9	DELTONA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
10	DELTONA EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	DOUGLAS AVENUE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	DUNNELLON TOWN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	EAGLENEST - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	EATONVILLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	ECON - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
16	EUSTIS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	EUSTIS SOUTH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	FERN PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
19	GROVELAND - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	HOLDER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	116.00	
21	HOLDER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
22	HOLDER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	14.00	
23	HOMOSASSA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	HOWEY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	INGLIS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	
26	INGLIS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	INVERNESS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
28	INVERNESS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	KELLER ROAD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	KELLY PARK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	LADY LAKE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	LAKE ALOMA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	LAKE EMMA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
34	LAKE HELEN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
35	LAKE WEIR - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	LEBANON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
37	LIBSON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	LOCKHART - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
39	LOCKWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	LONGWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2					1
29	2					2
19	1	1				3
9	1	1				4
100	2					5
30	1					6
90	3					7
75	1					8
120	3					9
90	3					10
60	2					11
40	2					12
19	2					13
90	3					14
100	2					15
60	2					16
63	2					17
30	1					18
40	2					19
250	1					20
250	1					21
19	2					22
20	1					23
13	1	1				24
100	1					25
9	1					26
160	2					27
60	2					28
60	2					29
9	1					30
29	2					31
100	2					32
100	2					33
55	2					34
19	2					35
10	1	1				36
40	2					37
100	2					38
30	1					39
40	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MAITLAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	MARICAMP - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	MARTIN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	MCINTOSH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	MINNEOLA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
6	MONTVERDE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
7	MOUNT DORA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	MYRTLE LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
9	NORTH LONGWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
10	NORTH LONGWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
11	OCALA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
12	OCOEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	OKAHUMPKA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	ORANGE BLOSSOM - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	ORANGE CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	14.00
16	ORANGE CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
17	OVIEDO - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	PIEDMONT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
19	PIEDMONT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	PLYMOUTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	PLYMOUTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	14.00	
22	RAINBOW SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	REDDICK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	SANTOS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	SILVER SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
26	SILVER SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	SILVER SPRINGS SHORES - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	SPRING LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	SPRING LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
30	TROPIC TERRACE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
31	TURNER PLANT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
32	TURNER PLANT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	TWIN COUNTY RANCH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	110.00	13.00	
34	TWIN COUNTY RANCH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
35	UNIV OF CENTRAL FL - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	UNIV OF CNTL FL NORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	UMATILLA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	WEIRSDALE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	WEKIVA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
40	WELCH ROAD - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Total Capacity (In MVa) (k)	Line No.
90	3					1
19	2					2
20	1					3
9	1					4
20	1					5
56	2					6
40	2					7
100	2					8
250	1					9
100	2					10
33	1					11
90	3					12
40	2					13
40	2					14
250	1					15
60	2					16
90	3					17
250	1					18
100	2					19
13	1	1				20
9	1					21
20	2					22
22	2					23
13	1					24
250	1					25
20	1					26
40	2					27
90	3					28
300	1					29
40	2					30
160	2					31
40	2					32
13	1	1				33
9	1					34
60	2					35
60	2					36
40	2					37
19	2					38
100	2					39
100	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WEST CHAPMAN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	WILDWOOD CITY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	WINTER GARDEN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	WINTER GARDEN CITRUS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	WINTER GARDEN CITRUS#2 - SOUTHERN FLORIDA	DIST - UNATTENDED	12.00		
6	WINTER GARDEN CITRUS#2 - SOUTHERN FLORIDA	DIST - UNATTENDED	12.00		
7	WINTER PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	WINTER PARK EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
9	WINTER PARK EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
10	WINTER SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
11	WINTER SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	WOODSMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
13	WOODSMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	ZELLWOOD - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	ZUBER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16					
17	AGRICOLA #4 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	ARBUCKLE CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	AVON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
20	AVON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	12.00
21	AVON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	AVON PARK - SOUTHERN FLORIDA REGION	DIS - UNATTENDED	69.00	13.00	
23	AVON PARK - SOUTHERN FLORIDA REGION	DIS - UNATTENDED	230.00	69.00	
24	AVON PARK NORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	BABSON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	BARNUM CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	BAY HILL - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	BITHLO - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	BOGGY MARSH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	BONNET CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	CABBAGE ISLAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	CANOE CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	4.00
33	CELEBRATION - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	CENTRAL PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	CHAMPIONS GATE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
36	CITRUSVILLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	CLEAR SPRINGS EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
38	COLONIAL - SOUTHERN FLORIDA REGION	DIST-UNATTENDED	69.00	13.00	
39	CONWAY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	COUNTRY OAKS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2					1
25	1					2
100	2					3
9	1	1				4
1	1					5
5	4					6
120	4					7
500	2					8
100	2					9
250	1					10
90	3					11
250	1					12
40	2					13
40	2					14
29	2					15
						16
9	1					17
8	1					18
200	1					19
150	1					20
40	2					21
80	1					22
250	1					23
40	2					24
20	1					25
60	2					26
90	3					27
50	2					28
100	2					29
60	2					30
60	2					31
30	1					32
60	2					33
90	3					34
20	1					35
20	1					36
20	1					37
30	1					38
40	2					39
40	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SUBSTATIONS

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3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CROOKED LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	14.00	
2	CURRY FORD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
3	CYPRESSWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	DACO - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	DAVENPORT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	DESOTO CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	DINNER LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	DUNDEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	EAST LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	EAST ORANGE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	FISHEATING CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	8.00
12	FISHEATING CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
14	FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	FOUR CORNERS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	FROSTPROOF - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	HAINES CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	HEMPLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	HEMPLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
20	HOLOPAW - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	25.00	
21	HORSE CREEK #2 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
22	HUNTERS CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	INTERNATIONAL DRIVE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
24	ISLEWORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	LAKE BRYAN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
26	LAKE BRYAN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	LAKE LUNTZ - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
28	LAKE MARION - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	LAKE OF THE HILLS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	LAKE PLACID - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	LAKE PLACID NORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
32	LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	LAKE WILSON - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	LAKEWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	LEISURE LAKES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	LITTLE PAYNE CREEK#1-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
37	LITTLE PAYNE CREEK#2-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
38	MAGNOLIA RANCH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	MAGNOLIA RANCH TEMP - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
40	MARLEY ROAD - SOUTHERN FLORIDA REGION	DIST- UNATTENDED	69.00	13.00	

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	1					1
50	1					2
40	2					3
13	1					4
20	1					5
19	2					6
75	2					7
20	1					8
19	2					9
120	3					10
150	1					11
9	1					12
200	1					13
9	1					14
90	3					15
50	2					16
80	2					17
60	1					18
34	1					19
25	2					20
9	1					21
110	3					22
100	2					23
19	2					24
500	2					25
90	3					26
100	2					27
20	1					28
20	1					29
40	2					30
11	2					31
60	2					32
40	2					33
55	2					34
9	1					35
13	1					36
13	1					37
60	2					38
20	1					39
30	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MEADOW WOODS EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
2	MEADOWS WOODS SOUTH-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
3	MEADOWS WOODS SOUTH-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	MIDWAY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
5	MULBERRY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	4.00	
6	NARCOOSEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	NORALYN #1 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
8	NORALYN #2 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
9	ODESSA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
10	ORANGEWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	PARKWAY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	PEMBROKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
13	PINECASTLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	POINCIANA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	POINCIANA NORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	REEDY LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	RIO PINAR - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
18	RIO PINAR - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	SAND LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	SAND MOUNTAIN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	SEBRING EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	SHINGLE CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	SKY LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
24	SKY LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	SOUTH BARTOW - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	SOUTH FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	
27	SOUTH FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
28	SUNFLOWER - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
29	SUN'N LAKES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	TAFT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	TAUNTON RD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	VINELAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	WAUCHULA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	WEST DAVENPORT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	14.00	
35	WEST LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
36	WEST LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	WESTRIDGE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	WEWAHOOTEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	13.00	4.00	
39	WEWAHOOTEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	WHIDDEN CREEK #1 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
33	1					1
200	1					2
60	2					3
33	1					4
6	1	1				5
90	3					6
9	3	1				7
9	1	1				8
30	1					9
100	2					10
60	3					11
2	1	1				12
40	2					13
100	2					14
30	1					15
40	2					16
500	2					17
100	2					18
80	2					19
9	1	1				20
20	1					21
60	2					22
250	1					23
90	3					24
9	1					25
19	1					26
45	2					27
30	1					28
40	2					29
60	2					30
20	1					31
60	2					32
19	2					33
19	2					34
250	1					35
13	1	1				36
50	1					37
9	1	1				38
13	1	1				39
20	1					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	WINDERMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
2	WINDERMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3					
4	TOTAL DISTRIBUTION		36373.00	7926.47	338.00
5					
6	BROOKRIDGE - COASTAL FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
7	BROOKRIDGE - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
8	BROOKRIDGE - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	133.00	
9	BROOKSVILLE WEST - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
10	HIGGINS PLANT - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
11	HUDSON - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
12	HUDSON - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	7.20
13	LAKE TARPON - COASTAL FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
14	NEW RIVER - COASTAL FLORIDA REGION	TRANS - UNATTTENDED	115.00	69.00	
15					
16	BRONSON - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
17	DRIFTON - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	5.00
18	GINNIE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
19	GUMBAY - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
20	HAVANA - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
21	IDYLWILD - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	138.00	67.00	12.00
22	QUINCY - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	4.00
23	SUWANNEE 230 KV - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
24	TALLAHASSEE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	8.00
25	WILCOX - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
26	LIBERTY - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	
27	ANDERSEN - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	14.00
28	BARBERVILLE - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	66.00	33.00
29	CAMP LAKE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	15.00
30	CAMP LAKE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
31	CENTRAL FLORIDA - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
32	CENTRAL FLORIDA - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
33	CLERMONT EAST - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	14.00
34	CRYSTAL RIVER EAST - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	116.00	
35	DALLAS - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
36	DELAND WEST - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
37	DELAND WEST - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	15.00
38	HAINES CREEK - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
39	MARTIN WEST - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
40	ROSS PRAIRIE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
200	1					1
40	2					2
						3
26704	593	48				4
						5
750	1					6
250	1					7
250	1					8
250	1					9
250	1					10
500	2					11
280	1					12
1500	2	1				13
280	1					14
						15
168	1					16
105	2					17
280	1					18
75	1					19
75	1					20
150	1					21
75	1					22
400	2					23
120	2					24
150	1					25
150	1					26
133	1					27
30	4	1				28
150	1					29
150	1					30
1500	2					31
450	2					32
250	1					33
250	1					34
280	1					35
200	1					36
125	1					37
250	1					38
200	1					39
150	1					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ROSS PRAIRIE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
2	SORRENTO - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
3					
4	AVALON - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
5	BARCOLA - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
6	GRIFFIN - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	13.00
7	INTERCESSION CITY - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
8	INTERCESSION CITY - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	13.00
9	KATHLEEN - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
10	NORTH BARTOW - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
11	SOUTH POLK - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
12	VANDOLAH - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	23.00
13					
14	TOTAL TRANSMISSION		10466.00	4193.00	260.20
15					
16					
17					
18					
19					
20					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
280	1					1
250	1					2
						3
250	1					4
150	1					5
250	1					6
250	1					7
280	1					8
750	1					9
150	1					10
168	1	1				11
400	2					12
						13
13354	56	3				14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
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Schedule Page: 426 Line No.: 1 Column: g

Single phase units are grouped and reported as a single transformer bank. Individual units are listed as separate line items.

Schedule Page: 426 Line No.: 15 Column: h

Spare transformers present at each substation are reported, but not included in the capacity rating of the station.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Asscociated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Accounting	PESC	various	4,680,416
3	Audit Services	PESC	various	2,425,979
4	Corporate Communications	PESC	various	4,337,887
5	Corporate Planning	PESC	various	5,694,374
6	Corporate Relations	PESC	various	3,536,289
7	Corporate Services	PESC	various	10,652,469
8	External Relations	PESC	various	4,013,094
9	Human Resources	PESC	various	5,679,535
10	Information Technology & Telecommunications	PESC	various	44,506,468
11	Investor Relations	PESC	various	602,534
12	Legal Services	PESC	various	5,138,878
13	Service Company Corporate	PESC	various	37,713,593
14	Supply Chain	PESC	various	2,385,093
15	Tax	PESC	various	2,175,552
16	Treasury and Enterprise Risk Management	PESC	various	2,882,825
17	Executive Management	PESC	various	9,887,219
18	Customer Service	PEC	various	1,472,431
19	Nuclear Generation	PEC	various	5,769,826
20	**Non-power Goods or Services Provided for Affiliate**			
21	Power Operations Group	PEC	146	753,177
22	Power Generation Engineering	PEC	146	2,615,993
23	Power Generation Business Improvement	PEC	146	1,319,790
24	Nuclear Generation	PEC	146	2,742,540
25	Customer Service	PEC	146	1,920,611
26	Transmission and Distribution	PEC	146	1,628,763
27	Network Services	PT Holdings	146	642,085
28	Revenue Sharing	PT Holdings	146	1,476,062
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Power Operations Group	PEC	various	7,869,818
3	Power Generation Business Improvement	PEC	various	709,417
4	Efficiency & Innovative Technologies	PEC	various	1,475,390
5	Fuels and Power Optimization	PEC	various	5,500,056
6	Transmission and Distribution	PEC	various	3,799,643
7	Information Technology and Telecommunications	PEC	various	2,416,368
8	Inventory Material	PEC	154,184	1,966,172
9	Financial Management	PEC	various	3,031,432
10	Property Management	PEC	107,931	1,258,100
11				
12				
13				
14				
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16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
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Schedule Page: 429 Line No.: 2 Column:

This includes both direct and indirect charges for goods or services such as Corporate Accounting, Property Accounting, and Disbursements. The method of allocation for indirect charges is based on Asset Ratio, Invoice Ratio, or Three Factor Ratio.

Schedule Page: 429 Line No.: 2 Column:

Progress Energy Service Company

Schedule Page: 429 Line No.: 2 Column:

107,181,186,408.1,566,908,920,921,923,926,930.2,930.1,930.2,935

Schedule Page: 429 Line No.: 3 Column:

This includes both direct and indirect charges for Audit services. The method of allocation for indirect charges is based on Asset Ratio.

Schedule Page: 429 Line No.: 3 Column:

408.1,920,921,923,926,930.1,930.2

Schedule Page: 429 Line No.: 4 Column:

This includes both direct and indirect charges for Corporate Communication goods or services. The method of allocation for indirect charges is based on Three Factor Ratio.

Schedule Page: 429 Line No.: 4 Column:

408.1,426.1,920,923,926,930.1,930.2,931,935,524,908,909,921

Schedule Page: 429 Line No.: 5 Column:

This includes both direct and indirect charges for goods or services such as Corporate Planning and Capital Planning & Project Assurance. The method of allocation for indirect charges is based on Asset Ratio, or Three Factor Ratio.

Schedule Page: 429 Line No.: 5 Column:

107,186,408.1,524,529,901,920,921,923,926,930.2,426.1,908,909,930.1,935,566

Schedule Page: 429 Line No.: 6 Column:

This includes both direct and indirect charges for Corporate Relations goods or services. The method of allocation for indirect charges is based on Three Factor Ratio.

Schedule Page: 429 Line No.: 6 Column:

408.1,426.4,920,921,923,925,926,930.2,931,107,184,228.4,426.1,502,524,566,

Schedule Page: 429 Line No.: 7 Column:

This includes both direct and indirect charges for goods or services such as Corporate Services Management, Corporate Security, Corporate Air, Corporate Headquarters, and Property Management. The method of allocation for indirect charges is based on Asset Ratio, Headcount Ratio, or Three Factor Ratio.

Schedule Page: 429 Line No.: 7 Column:

408.1,418,454,904,920,921,923,926,931,935,418,930.2,107,417.1,506,549,554,419,163,228.4,456,560,530,903

Schedule Page: 429 Line No.: 8 Column:

This includes both direct and indirect charges for External Relations goods or services. The method of allocation for indirect charges is based on Three Factor Ratio.

Schedule Page: 429 Line No.: 8 Column:

408.1,426.4,426.5,920,921,923,926,930.2,107,186,426.1,566,908,909,912,931

Schedule Page: 429 Line No.: 9 Column:

This includes both direct and indirect charges for goods or services such as Human Resources, and Human Resources Executive Benefits. The method of allocation for indirect charges is based on Headcount Ratio, or Three Factor Ratio.

Schedule Page: 429 Line No.: 9 Column:

925,408.1,426.1,920,921,923,926,930.1,930.2,184,517,524,566,908

Schedule Page: 429 Line No.: 10 Column:

This includes both direct and indirect charges for goods or services such as IT Infrastructure & Management, Telecommunications Infrastructure & Maintenance, Infrastructure Capital, Applications-Development & Enhancement, Telecom Client Projects, Wireless Services, Desktop Services, Business Applications Services, Multifunction Printing Devices(MPD)/Copier/Fax, and Application Operation-Mainframe. The method of allocation for indirect charges is based on Information Technology Distributed Cost Ratio, IT Standard Personal Computer & Device Rate, IT Application Chargeback Ratio, Headcount Ratio, or Three Factor Ratio.

Schedule Page: 429 Line No.: 10 Column:

107,183,184,186,408.1,417.1,500,506,510,524,551,554,566,570,580,586,588,590,905,908,912,920,921,923,926,151,501,520,547,517,528,587,101,108,154,549

Schedule Page: 429 Line No.: 11 Column:

This includes indirect charges for Investor Relations services. The method of allocation for indirect charges is based on Three Factor Ratio.

Schedule Page: 429 Line No.: 11 Column:

408.1,920,921,923,926,930.2,935

Schedule Page: 429 Line No.: 12 Column:

This includes both direct and indirect charges for Legal services. The method of allocation for indirect charges is based on Three Factor Ratio.

Schedule Page: 429 Line No.: 12 Column:

107,183,186,408.1,506,588,908,920,921,923,925,926,930.2,931,426.1,930.1

Schedule Page: 429 Line No.: 13 Column:

This includes both direct and indirect charges for goods or services such as Depreciation Expense, Property Tax, Interest Expense & Income, Leasehold Improvements, Property Insurance, Workers' Compensation, Other Insurance, Nuclear Premium & Credit, Progress Energy Service Company Corporate Expenses, FAS146, Operating Leases, Service Company Tax Expense & Tax Savings Initiative, Service Company Employee Incentives, Service Company Charges, and NuStart Earnings. The method of allocation for indirect charges is based on Asset Ratio, Headcount Ratio, Insurable Values Ratio, or Three Factor Ratio.

Schedule Page: 429 Line No.: 13 Column:

107,151,154,163,183,184,186,421,500,501,502,505,506,510,511,512,513,514,519,520,524,528,529,530,531,532,546,547,548,549,551,552,553,554,556,557,561.1,561.2,561.3,561.5,570,580,581,583,584,585,586,588,589,590,591,592,593,594,595,596,597,598,902,903,908,912,920,921,923,924,925,926,930.2,931,408.1,410.1,418,426.2,431,454

Schedule Page: 429 Line No.: 14 Column:

This includes both direct and indirect charges for goods or services such as Supply Chain, and Equipment Repairs. The method of allocation for indirect charges is based on Asset Ratio.

Schedule Page: 429 Line No.: 14 Column:

107,163,408.1,426.1,524,554,566,570,920,921,923,926,930.1,930.2

Schedule Page: 429 Line No.: 15 Column:

This includes both direct and indirect charges for goods or services such as Tax Services, and Payroll. The method of allocation for indirect charges is based on Three Factor Ratio, or Headcount Ratio.

Schedule Page: 429 Line No.: 15 Column:

408.1,920,921,923,926,930.2,931,935

Schedule Page: 429 Line No.: 16 Column:

This includes both direct and indirect charges for goods or services such as Treasury Operations & Management, and Analysis & Risk Management. The method of allocation for indirect charges is based on Three Factor Ratio, or Asset Ratio.

Schedule Page: 429 Line No.: 16 Column:

151,186,408.1,501,520,547,920,921,923,926,930.2,935

Schedule Page: 429 Line No.: 17 Column:

This includes indirect charges for goods or services such as Service Company Executive Benefits, Resource Sharing, and Senior Management. The method of allocation for indirect charges is based on Three Factor Ratio.

Schedule Page: 429 Line No.: 17 Column:

408.1,920,921,923,926

Schedule Page: 429 Line No.: 18 Column:

This includes both direct and indirect charges for goods or services such as Customer Calls, Management, and Performance Solutions. The method of allocation for indirect charges is based on Direct Cost, Total Customers Ratio or Total Agent-Handled Call Ratio.

Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 429 Line No.: 18 Column:

Progress Energy Carolinas

Schedule Page: 429 Line No.: 18 Column:

408.1, 417.1, 421, 580, 901, 903, 905, 908, 912, 913, 916, 926

Schedule Page: 429 Line No.: 19 Column:

This includes both direct and indirect charges for goods or services such as Analytical Services, Engineering & Programs, Information Technology, Management & Financial Services, Materials & Contracts Support, Nuclear Services Common Miscellaneous Services & Shared Resources, Nuclear Security Support, and Regulatory, Assessment & Oversight. The method of allocation for indirect charges is based on Direct Cost Ratio, Maximum Dependable Capacity Ratio or Level of Service Estimate.

Schedule Page: 429 Line No.: 19 Column:

107, 163, 183, 408.1, 506, 512, 513, 514, 517, 518, 519, 520, 524, 528, 529, 530, 531, 532, 549, 566, 592, 920, 921, 923, 926, 930.1, 935

Schedule Page: 429 Line No.: 21 Column:

This includes both direct and indirect charges for goods or services such as CT Services, Engineering, Management & Financial Services, Operations Support, Generation & Transmission Construction, and Plant Operations. The method of allocation for indirect charges is based on Direct Cost Ratio, Level of Service Estimate, or Maximum Dependable Capacity Ratio.

Schedule Page: 429 Line No.: 21 Column:

Progress Energy Carolinas

Schedule Page: 429 Line No.: 22 Column:

This includes direct charges for Power Generation Engineering goods or services.

Schedule Page: 429 Line No.: 23 Column:

This includes both direct and indirect charges for Power Generation Business Improvement goods or services. The method of allocation for indirect charges is based on Direct Cost Ratio, Level of Service Estimate, or Maximum Dependable Capacity Ratio.

Schedule Page: 429 Line No.: 24 Column:

This includes direct charges for goods or services such as Analytical Services, Engineering & Programs, Information Technology, Management & Financial Services, Materials & Contracts Support, Nuclear Services Common Miscellaneous Services & Shared Resources, Nuclear Security Support, and Regulatory, Assessment & Oversight.

Schedule Page: 429 Line No.: 25 Column:

This includes both direct and indirect charges for goods or services such as Customer Calls, Management, and Performance Solutions. The method of allocation for indirect charges is based on Direct Cost Ratio, Total Customers Ratio, or Total Agent-Handled Calls Ratio.

Schedule Page: 429 Line No.: 26 Column:

This includes both direct and indirect charges for goods or services such as Distribution Design, and Management & Oversight. The method of allocation for indirect charges is based on Direct Cost Ratio, Labor Dollar Ratio, Labor Dollar Adder, Screening Unit Rate, or Headcount Ratio.

Schedule Page: 429 Line No.: 27 Column:

This includes direct charges for Network goods or services.

Schedule Page: 429 Line No.: 27 Column:

Progress Telecommunications Holding Company

Schedule Page: 429 Line No.: 28 Column:

This includes direct charges for Revenue Sharing goods or services.

Schedule Page: 429.1 Line No.: 2 Column:

This includes both direct and indirect charges for goods or services such as CT Services, Engineering, Management & Financial Services, Operations Support, Generation & Transmission Construction, and Plant Operations. The method of allocation for indirect charges is based on Direct Cost Ratio, Level of Service Estimate or Maximum Dependable Capacity Ratio.

Schedule Page: 429.1 Line No.: 2 Column:

107, 151, 163, 183, 184, 408.1, 417.1, 500, 506, 511, 512, 513, 514, 524, 529, 530, 531, 532, 546, 548, 549, 553, 554, 566, 570, 571, 573, 592, 920, 921, 923, 926

Schedule Page: 429.1 Line No.: 3 Column:

This includes both direct and indirect charges for Power Generation Business Improvement goods or services. The method of allocation for indirect charges is based on Direct Cost Ratio, Level of Service Estimate or Maximum Dependable Capacity Ratio.

Schedule Page: 429.1 Line No.: 3 Column:

107, 184, 408.1, 506, 513, 531, 546, 549, 920, 926

Schedule Page: 429.1 Line No.: 4 Column:

This includes both direct and indirect charges for goods or services such as Co-Generation Contract Support, Joint Owner Contract Support, Purchased Power Contract Support, Wholesale Term Contracts & Management, and Financial Services. The method of allocation for indirect charges is based on Direct Cost Ratio, Maximum Dependable Capacity Ratio or Level of Service Estimate.

Schedule Page: 429.1 Line No.: 4 Column:

183, 408.1, 417.1, 421, 908, 909, 912, 916, 920, 921, 923, 926, 930

Schedule Page: 429.1 Line No.: 5 Column:

This includes both direct and indirect charges for goods or services such as Coal, Re-agents Procurement, By-Product Commercial Management & Transportation; Fuel Forecasting; Fuel Planning; Gas Procurement; Oil Procurement; Financial Services; Portfolio Management; and Power Trading. The method of allocation for indirect charges is based on Direct Cost Ratio, Coal Volume Allocation or Level of Service Estimate.

Schedule Page: 429.1 Line No.: 5 Column:

151, 408.1, 501, 520, 547, 920, 921, 923, 926

Schedule Page: 429.1 Line No.: 6 Column:

This includes both direct and indirect charges for goods or services such as Distribution Design, and Management & Oversight. The method of allocation for indirect charges is based on Direct Cost Ratio, Labor Dollar Ratio, Labor Dollar Adder, Screening Unit Rate or Headcount Ratio.

Schedule Page: 429.1 Line No.: 6 Column:

107, 151, 163, 408.1, 511, 512, 513, 514, 528, 529, 531, 532, 553, 554, 556, 560, 561, 561.1, 561.2, 561.3, 562, 566, 568, 569.1, 569.2, 569.3, 570, 571, 573, 580, 583, 588, 589, 592, 920, 921, 926

Schedule Page: 429.1 Line No.: 7 Column:

This includes indirect charges for goods or services such as Applications-Development & Enhancement, Wireless Services, IT Desktop Services, Business Applications Services, Passport Operations & Maintenance, and Energy Delivery Management & Oversight. The method of allocation is based on Level of Service Estimate or Maximum Dependable Capacity Ratio.

Schedule Page: 429.1 Line No.: 7 Column:

151, 184, 421, 501, 506, 517, 520, 528, 547, 549, 588, 905, 908, 920, 921, 923

Schedule Page: 429.1 Line No.: 8 Column:

This includes direct charges for Inventory goods.

Schedule Page: 429.1 Line No.: 9 Column:

This includes both direct and indirect charges for goods or services such as Cost Management & Budgeting Support, Internal Reporting, Capital Project Support, and Capital Project Controls & Assurance. The method of allocation is based on Level of Service Estimate or Maximum Dependable Capacity Ratio.

Schedule Page: 429.1 Line No.: 9 Column:

107, 151, 183, 184, 408.1, 426.4, 501, 506, 517, 520, 524, 528, 547, 549, 560, 566, 920, 921, 923, 926

Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 429.1 Line No.: 10 Column:

This includes direct charges for Engineering & Programs, and Commercial Real Estate & Furnishings.

INDEX

Schedule	Page No.

Diversification Report

2009

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2009

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Affiliation or Connection	Name and Address	
Jeffrey Corbett	Sr. Vice President, Energy Delivery	Director	Chi Chi Rodriguez Foundation	Tampa, FL
		Director	Salvador Dali Museum	St. Petersburg, FL
		Director	Junior Achievement of West Central Florida	
Vincent M. Dolan	Presdient	Board of Directors	All Children's Hopital	St. Petersburg, FL
		Trustee	Business Industry Political Action Committee (BIPAC)	
		Board of Directors	Dali Museum	St. Petersburg, FL
		Board of Directors	Enterprise Florida, Inc.	
		Trustee	Florida Chamber of Commerce-FL Chamber Foundation	
		Resident Member	Florida Council of 100	
		Member	Florida High Tech Corridor Council	
		Board of Directors	Florida Tax Watch	
		Board of Directors	Southern Electric Exchnage	
		Board of Directors/ Executive Committee	Tampa Bay Partnership	
Will A. Garrett	Controller	None		
William D. Johnson	Chairman and CEO	Director, Executive Comm	Institute of Nuclear Power Operations	
		Director	Edison Electric Institute	
		Chairman	Carolina Power & Light Company, DBA Progress Energy	
		Chairman	Florida Power Corporation- DBA Progress Energy	
		Chief Executive Officer	Florida Progress Corporation	
		Board Member	North Carolina Chamber Board	
		Chairman	Progress Capital Holdings, Inc.	
		President	Progress Energy Foundation, Inc.	
		Chief Executive Officer	Progress Energy, Inc.	
		Chairman	Progress Fuels Corporation	
		Chairman	Progress Holdings, Inc	
		Chairman	Progress Real Estate Holdings, Inc.	
		Chairman	Progress Ventures, Inc.	
Michael Lewis	Senior Vice President	Board Member	Eckerd Youth Alternatives	
		Board Member	Junior Achievement of West Central Florida	
		Director	Mahaffey Theater Foundation	
		Governors Council	Metro Orlando Economic Development Commission	
		Board Member	Pinellas Education Foundation	
		Board Member	United Way of Tampa Bay	
Jeff Lyash	Executive Vice President	Chairman	A Baseball Community Coalition	
		Board of Directors	Electric Power Research Institute	
		Director	Florida Chamber of Commerce	
		Director	SunTrust Bank	North Carolina
		Trustees	Florida Chamber of Foundation	
John R. McArthur	Senior Vice President	Board of Directors	Carolina Power & Light Company, DBA Progress Energy	Carolinas, Inc.
		Board of Directors	Florida Power Corporation	
		Board of Directors	Florida Progress Corporation	
		Board of Directors	Progress Capital Holdings, Inc.	
		Board of Directors	Progress Energy Foundation, Inc.	
		Board of Directors	Progress Energy Service Company, LLC	
		Board of Directors	Progress Energy, Inc.	
		Board of Directors	Progress Fuels Corporation	
		Board of Directors	Progress Telecommunications Corporation	
		Board of Directors	Progress Ventures, Inc.	
		Board of Directors	PV Holdings, Inc.	
		Board of Directors	Strategic Resource Solutions	
Mark Mulhern	Senior VP Finance and CFO	Board of Directors	Capitan Corporation	
		Board of Directors	Care found Inc.	
		Board of Directors	Carolina Power & Light Company	
		Board of Directors	ExCo	
		Board of Directors	Florida Power Corporation	
		Board of Directors	Florida Progress Corporation	
		Board of Directors	Florida Progress Funding Corporation	
		Board of Directors	Habitat for Humanity	
		Board of Directors	PIH Inc.	
		Board of Directors	PIH Tax Credit Fund Inc.	
		Board of Directors	Progress Energy	
		President	Progress Fuels Corporation	
		President	Progress Synfuel Holdings, Inc.	
		President	Progress Ventures, Inc.	
		President	PV Holdings, Inc.	

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2009

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
James Scarola	Sr. Vice President	Board Member	Parr Shoals Reactor (Carolina/Virginia Corp Board)
		Board Member	University of South Carolina's Nuclear Engineering Advisory Board
Frank A. Schiller	General Counsel	Director	Capitan Corporation
		Director	Caro fund, Inc.
		Officer	Caro Home, LLC
		Director	Carolina Power & Light Company
		Director	Florida Progress Funding Corporation
		Director	Florida Power Corporation
		Officer	Florida Progress Corporation
		Director	Kentucky May Coal Company, Inc.
		Officer	PFC Property Holdings, Inc.
		Director	PIH Tax Credit Fund Inc.
		Director	PIH, Inc.
		Officer	Progress Capital Holdings, Inc.
		Director	Progress Energy Envirotree, Inc.
		Officer	Progress Energy, Inc.
		Officer	Progress Energy Service Company, LLC
		Officer	Progress Fuels Corporation
		Director	Progress Synfuel Holdings, Inc.
		Director	Progress Telecommunications Corporation
		Director	Strategic Resource Solutions, Inc.
		Officer	Progress Ventures, Inc.
		Officer	PV Holdings, Inc.
Paula Sims	Sr. Vice President	Board of Trustees	Meredith College
Jeffrey M. Stone	Chief Accounting Officer	None	
Thomas R. Sullivan	Vice President, Treasurer	None	
Lloyd Yates	President and CEO, PGN Carolinas	Board of Directors	Association of Edison Illuminating Companies
		Board of Directors	North Carolina Community College Foundation Board
		Board of Directors	North Carolina Economic Development Committee
		Board Member	Salvation Army
		Board Member	Winston Salem Urban League

Business Contracts with Officers, Directors and Affiliates

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2009

List all contracts, agreements, or other business arrangements* entered into during the calendar year (other than compensation-related to position with respondent) between the respondent and each officer and director listed in Part 1 of the Executive Summary. In addition, provide the same information with respect to professional services for each firm, partnership, or organization with which the officer or director is affiliated.

Note: * Business agreement, for this schedule, shall mean any oral or written business deal which binds the concerned parties for products or services during the reporting year or future years.

Name of Officer or Director	Name and Address of Affiliated Entity	Amount	Identification of Product or Service
Vincent Dolan	Tampa Bay Partnership, Inc. Tampa, FL	5,000	Donation
Jeff Lyash	The Florida Council of 100 Tallahassee, Florida	2,500	Dues
Jeff Lyash	The Florida Orchestra Guild Tampa, FL	2,500	Donation
Jeff Lyash	Junior Achievement Inc.	10,000	Donations
Mark Wimberly	Pasco Education Foundation	2,500	Donations
Vincent Dolan	Pinellas Education Foundation	2,500	Donations

Reconciliation of Gross Operating Revenues
Annual Report versus Regulatory Assessment Fee Return

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2009

For the current year, reconcile the gross operating revenues as reported on Page 300 of this report with the gross operating revenues as reported on the utility's regulatory assessment fee return. Explain and justify any differences between the reported gross operating revenues in column (h).

Line No.	(a) Description	(b) Gross Operating Revenues per Page 300	(c) Interstate and Sales for Resale Adjustments	(d) Adjusted Intrastate Gross Operating Revenues	(e) Gross Operating Revenues per RAF Return	(f) Interstate and Sales for Resale Adjustments	(g) Adjusted Intrastate Gross Operating Revenues	(h) Difference (d) - (g)
1	Total Sales to Ultimate Customers (440-446, 448)	$ 4,647,833,873	$ 39,707,954	$ 4,608,125,919	$ 4,647,833,873	$ 39,707,954	$ 4,608,125,919	$ -
2	Sales for Resale (447)	410,163,456	410,163,456	-	410,163,456	410,163,456	-	0
3	Total Sales of Electricity	5,057,997,329	449,871,410	4,608,125,919	5,057,997,329	449,871,410	4,608,125,919	0
4	Provision for Rate Refunds (449.1)	(68,669)	(68,669)	-	(68,669)	(68,669)	-	0
5	Total Net Sales of Electricity	5,057,928,660	449,802,741	4,608,125,919	5,057,928,660	449,802,741	4,608,125,919	0
6	Total Other Operating Revenues (450-456)	192,693,053	52,054,373	140,638,680	192,693,053	52,054,373	140,638,680	-
7	Other (Specify)							
8								
9								
10	**Total Gross Operating Revenues**	$ 5,250,621,713	$ 501,857,114	$ 4,748,764,599	$ 5,250,621,713	$ 501,857,114	$ 4,748,764,599	$ -

Analysis of Diversification Activity
Changes in Corporate Structure

Company:

For the Year Ended December 31, 2009

Provide any changes in corporate structure including partnerships, minority interest, and joint ventures and an updated organizational chart, including all affiliates.

Effective Date (a)	**Description of Change (b)**
3/2/2009	Progress Reinsurance Company Ltd. was dissolved
4/30/2009	CP & L's ownership interest in Microcell Corporation to 2.73%. The increase is due to additional investment in shares of the entity
2/18/2009	CP & L's 99% limited partnership interest in Better Homes for Garner LP was assigned to an outside party.
12/31/2009	PFC Receivables, Inc. was dissolved
12/31/2009	PV Holdings, Inc. was reorganized and its names was changed to Progress Ventures Holdings, Inc.

Analysis of Diversification Activity

New or Amended Contracts with Affiliated Companies

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2009

Provide a synopsis of each new or amended contract, agreement, or arrangement with affiliated companies for the purchase, lease, or sale of land, goods, or services (excluding tariffed items). The synopsis shall include, at the minimum, the terms, price, quantity, amount, and duration of the contracts.

Name of Affiliated Company (a)	Synopsis of Contract (b)
No new or amended affiliated contracts in 2009.	

Analysis of Diversification Activity
Individual Affiliated Transactions in Excess of $500,000

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2009

Provide information regarding individual affiliated transactions in excess of $500,000. Recurring monthly affiliated transactions which exceed $500,000 per month should be reported annually in the aggregate. However, each land or property sales transaction even though similar sales recur, should be reported as a "non-recurring" item for the period in which it occurs.

Name of Affiliate (a)	Description of Transaction (b)	Dollar Amount (c)
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)(as service provider)	Recurring monthly shared utility functions and services. See page 457 for description.	50,236,674
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)(as service provider)	Credit resulting from enterprise wide nuclear COLA and other nuclear project adjustments	(14,499,113)
Progress Energy Service Company LLC (as service provider)	Recurring monthly Service Company functions and services. See Page 457 for description.	$ 141,540,612
Progress Energy Service Company LLC (as service	Non-recurring sale of desktop and laptop computers See Page 457 for description.	5,429,698

Analysis of Diversification Activity
Summary of Affiliated Transfers and Cost Allocations

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2009

Grouped by affiliate, list each contract, agreement, or other business transaction exceeding a cumulative amount of $300 in any one year, entered into between the Respondent and an affiliated business or financial organization, firm, or parthership identifying parties, amounts, dates, and product, asset, or service involved.

(a) Enter name of affiliate.
(b) Give description of type of service, or name the product involved.
(c) Enter contract or agreement effective dates.
(d) Enter the letter "p" if the service or product is purchased by the Respondent: "s" if the service or product is sold by Respondent.
(e) Enter utility account number in which charges are recorded.
(f) Enter total amount paid, received, or accrued during the year for each type of service or product listed in column (c). Do not net amounts when services are both received and provided.

Name of Affiliate (a)	Type of Service and/or Name of Product (b)	Relevant Contract or Agreement and Effective Date (c)	"p" or "s" (d)	Total Charge for Year: Account Number (e)	Total Charge for Year: Dollar Amount (f)
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Direct and indirect charges for shared utility functions and services such as customer services, nuclear generation services, power operations support, power generation engineering support, efficiency and innovative technologies support, fuels and power optimization support, transmission and distribution support, IT&T support, and financial management.	Utility Service Agreement 1/1/2001	S	1460001	11,096,933
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Direct and indirect charges for shared utility functions and services such as customer services, nuclear generation services, power operations support, efficiency and innovative technologies support, fuels and power optimization support, transmission and distribution support, IT&T support, inventory, financial management, and property management.	Utility Service Agreement 1/1/2001	P	2340001	35,737,561
PT Holdings Company LLC	Network Services, Land Lease, Revenue Sharing	Master Service and Wireless Attachment Agreements - 12/19/2003	S	1460071	2,166,543
Progress Energy Service Company LLC	Shared corporate functions including accounting and finance, audit, communications, planning and project assurance, corporate relations, corporate services and corporate services management, facilities and real estate management, security services, senior management, external relations, human resources, information technology & telecommunications, investor relations, legal, state public affairs & economic development, supply chain services and equipment repairs, payroll, tax, treasury, insurance and risk management, mail services. Plus direct operational support provided upon request from affiliate in support of affiliate projects. Sale of desktop and laptop computers. Excludes convenience payments and pay agent transactions.	Utility Service Agreement 12/1/2000	P	2340098	146,970,310

Analysis of Diversification Activity
Assets or Rights Purchased from or Sold to Affiliates

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2009

Provide a summary of affiliated transactions involving asset transfers or the right to use assets.

Name of Affiliate	Description of Asset or Right	Cost/Orig. Cost	Accumulated Depreciation	Net Book Value	Fair Market Value	Purchase Price	Title Passed Yes/No
Purchases from Affiliates:							
Progress Energy Service Company LLC (as service provider)	Non-recurring sale of desktop and laptop computers	$ 5,429,698		$ 5,429,698	$ 5,429,698	$ 5,429,698	
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)(as service provider)	Credit resulting from enterprise wide nuclear COLA and other nuclear project adjustments	$ (14,499,113)		$ (14,499,113)	$ (14,499,113)	$ (14,499,113)	
Total		$ (9,069,415)	-	$ (9,069,415)	$ (9,069,415)	$ (9,069,415)	
Sales to Affiliates:		$	$	$	$	**Sales Price**	
Total						$ -	

Analysis of Diversification Activity
Employee Transfers

Company: *Progress Energy Florida, Inc.*

For the Year Ended December 31, 2009

List employees earning more than $30,000 annually transferred to/from the utility to/from an affiliate company.

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
SVC	FPC	Public Affairs Assistant	Public Affairs Assistant	Permanent
FPC	CPL	Sr Construction Mgr	Sr Construction Mgr	Permanent
SVC	FPC	Admin Assistant I	Admin Assistant I	Permanent
SVC	FPC	VP-External Relations-PEF	President & CEO-PGN Florida	Permanent
FPC	CPL	Nucl Tech Trng Instructor	Sr Nucl Self Evaluation Spec	Permanent
FPC	CPL	Mgr-Maint-Nuc	Mgr-Maintenance-BNP	Permanent
SVC	FPC	Public Policy Analyst-CRAS	Public Policy Analyst-CRAS	Permanent
SVC	FPC	Mgr-Public Policy & Constituen	Mgr-Public Policy & Constituen	Permanent
SVC	FPC	Public Policy Analyst-CRAS	Public Policy Analyst-CRAS	Permanent
CPL	FPC	Mgr-Maint-Nuc	Mgr-Maint-Nuc	Permanent
SVC	FPC	Mgr-PEF Sourcing	Mgr-PEF Sourcing	Permanent
FPC	SVC	Sr Bus Fin Anlyst	Sr Regulatory Spec (INT)	Permanent
SVC	FPC	Sr Econ Dev Exec	Sr Econ Dev Exec	Permanent
CPL	FPC	Mgr-Maint-Nuc	Mgr-Nuclear Oversight (IO)	Permanent
FPC	CPL	Supv-Emergency Prep	NGG Fleet Emer Prepard Mgr	Permanent
CPL	FPC	Lead Proj Controls Spec	Lead Proj Controls Spec	Permanent
FPC	SVC	Program Leader-Contracts NPC	Sr Proj Assur Advisor -R(01/10	Permanent
SVC	FPC	Lead Reg Affairs Anlyst	Lead Reg Affairs Anlyst	Permanent
FPC	SVC	Sr Land Acquis/Dispos Spec	SrSuppDiv&BusDevCoord-CS	Permanent
CPL	FPC	Mgr-Nuc Info Tech	Mgr-Nuc Info Tech	Permanent
FPC	CPL	President & CEO-PGN Florida	Exec VP-Corporate Development	Permanent
FPC	SVC	Lead Environmental Specialist	Lead Environmental Specialist	Permanent
CPL	FPC	Intern	Intern	Permanent
CPL	FPC	Assessor-RNAS	Sr Nucl Opers Spec	Permanent
SVC	FPC	Admin Asst to Department Head	Admin Asst to Department Head	Permanent
SVC	FPC	Program Mgmt Spec-Ext Rel	Program Mgmt Spec-Ext Rel	Permanent
FPC	SVC	LINC Proj Mgr	Dir-Strategic Sourcing	Permanent
SVC	FPC	Sr Regulatory Spec (INT)	Sr Bus Fin Anlyst	Permanent
SVC	FPC	Sr Econ Dev Exec	Sr Econ Dev Exec	Permanent
CPL	FPC	NGG Plant General Mgr	Dir-Nuclear Upgrades	Permanent
SVC	FPC	Sr Proj Assur Advisor -R(01/10	Sr Proj Assur Advisor -R(01/10	Permanent
SVC	FPC	Sr Regulatory Spec	Sr Regulatory Spec	Permanent
FPC	CPL	Plt Mgr-Anclote	Gen Mgr-Trans Maint	Permanent
FPC	SVC	Mgr-PEF Planning & Strategy	Dir-Supply Chain Ctr of Excell	Permanent
FPC	CPL	Sr Logistics Planning Anlyst	Supv-Materials-POG	Permanent
SVC	FPC	Dir-External Relations-PEF	Dir-External Relations-PEF	Permanent
SVC	FPC	Grass Roots Coord-PUB AFF	Grass Roots Coord-PUB AFF	Permanent
FPC	CPL	System Protection & Cntrl Tech	Relay Tech II	Permanent
FPC	CPL	Electrician Apprent-Substation	Assoc Engr Technical Supt Spec	Permanent
FPC	SVC	Mgr-Materials & Services	Mgr-PEF Sourcing	Permanent
FPC	CPL	Engineer I	Engineer I	Permanent

Analysis of Diversification Activity

Non-Tariffed Services and Products Provided by the Utility

Company:

For the Year Ended December 31, 2009

Provide the following information regarding all non-tariffed services and products provided by the utility.

Description of Product or Service (a)	Account No. (b)	Regulated or Non-regulated (c)
Rent from Electric Properties	4540001	Regulated
Managed Services	4170001	Non-Regulated
Turnkey Solutions	4170001	Non-Regulated
Power Quality Services	4170001	Non-Regulated
Homewire	4170001	Non-Regulated
Water Heater Repair	4170001	Non-Regulated
All-Connect	4170001	Non-Regulated
Lighting	4170001	Non-Regulated
Infrared Scanning Services	4170001	Non-Regulated
High Voltage Services	4170001	Non-Regulated
Distribution Services	4170001	Non-Regulated
Vegetation Services	4170001	Non-Regulated
Transformer Services	4170001	Non-Regulated
Material Solutions	4170001	Non-Regulated
Joint Trenching	4170001	Non-Regulated
General System Planning	4170001	Non-Regulated
Transmission Design	4170001	Non-Regulated
Transmission Construction & Maintenance	4170001	Non-Regulated
Substation Design, Construction & Maintenance	4170001	Non-Regulated
System Protection & Control, Fiber Optic & Meter Services	4170001	Non-Regulated
Wireless Transmission Tower Attachments	4210708	Non-Regulated

Nonutility Property (Account 121)

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2009

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of nonutility property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor items (5% of the balance at the end of the year, for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service, or (2) other property nonutility property.

Description and Location	Balance at beginning of year	Purchases, Sales, Transfers, etc.	Balance at end of year
Previously Devoted to Public Service			
Land - Marion County - Florida	$ 135,191		$ 135,191
Structures - Pinellas County, Florida	177,011		177,011
Minor Items	177,712	1,151	178,863
Not Previously Devoted to Public Service			
Land - Volusia County, Florida	1,622,391		1,622,391
Equipment - Meters System (Florida)	5,423,549		5,423,549
Equipment - Walk of Fame, St. Pete, FL	1,380,193		1,380,193
Other	675,480		675,480
Generators on Customer premises	732,987		732,987
Communication Equipment	0		0
Totals	$ 10,324,515	$ 1,151	$ 10,325,666

Number of Electric Department Employees

Company: Progress Energy Florida, Inc.
For the Year Ended December 31, 2009

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	**10/25/2009**
2. Total Regular Full-Time Employees	**3986**
3. Total Part-Time and Temporary Employees	**438**
4. Total Employees	**4424**

Details

Regular Part Time:	7
Temp Full Time:	426
Temp Part Time:	5

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Company: Florida Power Corporation
For the Year Ended December 31, 2009

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425) -- Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Item	Amount
Account 426 - Miscellaneous Income Deductions	
Donations	
Civic & Community Organizations	345,780.49
Cultural & Art Organizations	804,749.57
Economic Development	411,954.08
Education Related Contributions	1,594,662.12
Educational Institutions & Charitable Organizations	3,500,000.00
Health & Human Services Contributions	786,623.34
Other	21,510.08
Subtotal Accounts 426100F, 4261013, 4261014, 426180T	7,465,279.68
Investment in Company Owned Life Insurance	(5,623,798.27)
Subtotal Accounts 4262016, 4262041	(5,623,798.27)
Certain Civic, Political & Related Activities	2,301,606.91
Subtotal Accounts 4264200, 4264300	2,301,606.91
Other Deductions	1,400,185.71
Subtotal Accounts 4265001, 4265007	1,400,185.71
Total Miscellaneous Income Deductions - Account 426	5,543,274.03
Account 430 - Interest of Debt to Associated Companies	
Money Pool (Avg Rate 0.69%)	2,755,141.22
Total Interest on Debt to Associated Companies - Account 430	2,755,141.22
Account 431 - Other Interest Expense	
Commitment Fees (4310010)	339,997.64
Other Interest Expense (4310001, 4310010, 4310011)	243,172.55
Customer Deposits - Rate 6 to 7% per annum	11,955,185.79
Interest related to OPC Petition Customer Refund - Rate 1.7%	579,121.00
Interest related to Projected Tax Deficiency on various audit issues - Rate 6.6%	583,198.77
Derivative Collateral Interest (various rates)	1,195,053.92
Total Other Interest Expense - Account 431	14,895,729.67

Budgeted and Actual In-Service Costs of Nuclear Power Plant

Company: *Progress Energy - Florida* *[Section (8)(f)]*

For the Year Ended December 31, 2009

Report the budgeted and actual costs as compared to the estimated in-service costs of the proposed power plant as provided in the petition for need determination or revised estimate as necessary. Per Rule 25-6.0423(8)(f)

Item				
Plant Name: Crystal River Unit 3 Uprate	**Actual Costs as of December 31, (insert year): 2009**	**Remaining Budgeted Costs to Complete Plant:**	**Total Estimated Cost of Plant** Note (1)	**Estimated Cost provided in the Petition for Need Determination (or revised estimate as necessary)** Note (2)
Licensing/Permits/Authorizations/Legal	$ 20,898,842	$ 2,693,168	$ 23,592,010	$0
Site/Site Preparation	$ -	$ -	$ -	0
Related Facilities Note (3)	$ -		$ -	49,450,000
Generation Plant	$ 180,623,138	$ 155,919,985	$ 336,543,123	287,500,000
Transmission Facilities	$ -	$ -	$ -	102,350,000
Total	$ 201,521,980	$ 158,613,153	$ 360,135,133	$ 439,300,000

(1) Estimated costs included herein are exclusive of Cost of Removal.

(2) Estimated costs provided in the petition for need determination are based on estimates provided in CR3 Power Uprate Need proceeding, Docket # 060642-EI. These numbers have been increased by 15% for indirect costs to make them comparable to the estimated cost of plant amounts which also include the indirect costs.

(3) Related Facilities included the POD project balance per the Need Determination, but for schedule purposes, these costs are captured within the Generation Plant line item.

Budgeted and Actual In-Service Costs of Nuclear Power Plant

CONFIDENTIAL

[Section (8)(f)]

Company: Progress Energy - Florida

For the Year Ended December 31, 2009

Report the budgeted and actual costs as compared to the estimated in-service costs of the proposed power plant as provided in the petition for need determination or revised estimate as necessary. Per Rule 25-6.0423(8)(f)

Item	Actual Costs as of December 31, (insert year): 2009	Remaining Budgeted Costs to Complete Plant:	Total Estimated Cost of Plant	Note 1 Estimated Cost provided in the Petition for Need Determination (or revised estimate as necessary)
Plant Name: Levy County Nuclear Unit 1 and 2				
Licensing/Permits/Authorizations/Legal	$ 83,161,390	[redacted]		$ -
Site/Site Preparation	$ 66,236,158	[redacted]		$ -
Related Facilities	$ 144,363	[redacted]		$ -
Generation Plant	$ 355,520,213	[redacted]		$ 10,516,097,000
Transmission Facilities	$ 23,085,308	[redacted]		$ 2,446,841,000
Total (Note 2)	$ 528,147,432	[redacted]		$ 12,962,938,000

Note 1: These amounts are based on our Need Determination which was filed March 11, 2008. At that point PEF did not have negotiated or signed contracts in place. Therefore the estimates provided are high level and only broken out between generation and transmission as presented in the Need Petition. As the project continues PEF will have better estimates and contracts in place.

Note 2: Costs included herein are exclusive of AFUDC and Carrying Costs as well as initial fuel load costs.