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

EI801-07-AR

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

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** 2007/Q4

Deloitte.

Deloitte & Touche LLP
Suite 1800
150 Fayetteville Street Mall
Raleigh, NC 27601
USA

Tel: +1 919 546 8000
Fax: +1 919 833 3276
www.deloitte.com

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Florida Power Corporation d/b/a Progress Energy Florida, Inc.
Raleigh, North Carolina

We have audited the balance sheet—regulatory basis of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (the "Company") as of December 31, 2007, and the related statement of income—regulatory basis; retained earnings—regulatory basis; cash flows—regulatory basis; and accumulated other comprehensive income, comprehensive income, and hedging activities—regulatory basis for the year ended December 31, 2007, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 1, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

As discussed in Note 14 to the financial statements, on January 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48.

In our opinion, such regulatory-basis financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of Florida Power Corporation d/b/a Progress Energy Florida, Inc. as of December 31, 2007, and the results of its operations and its cash flows for the year ended December 31, 2007, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the board of directors and management of Florida Power Corporation d/b/a Progress Energy Florida, Inc. and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

February 28, 2008

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.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

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 2007/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 Lee	06 Title of Contact Person Manager-Regulatory 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)* 12/31/2007

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 Peter M. Scott III	03 Signature Peter M. Scott III	04 Date Signed *(Mo, Da, Yr)* 04/18/2008
02 Title Executive Vice President and CFO		

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	12/31/2007	End of 2007/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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	None
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	None
17	Electric Plant Held for Future Use	214	
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	None
21	Materials and Supplies	227	
22	Allowances	228-229	
23	Extraordinary Property Losses	230	
24	Unrecovered Plant and Regulatory Study Costs	230	None
25	Transmission Service and Generation Interconnection Study Costs	231	
26	Other Regulatory Assets	232	
27	Miscellaneous Deferred Debits	233	
28	Accumulated Deferred Income Taxes	234	
29	Capital Stock	250-251	
30	Other Paid-in Capital	253	
31	Capital Stock Expense	254	None
32	Long-Term Debt	256-257	
33	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
34	Taxes Accrued, Prepaid and Charged During the Year	262-263	
35	Accumulated Deferred Investment Tax Credits	266-267	
36	Other Deferred Credits	269	

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	12/31/2007	End of 2007/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
38	Accumulated Deferred Income Taxes-Other Property	274-275	
39	Accumulated Deferred Income Taxes-Other	276-277	
40	Other Regulatory Liabilities	278	
41	Electric Operating Revenues	300-301	
42	Sales of Electricity by Rate Schedules	304	
43	Sales for Resale	310-311	
44	Electric Operation and Maintenance Expenses	320-323	
45	Purchased Power	326-327	
46	Transmission of Electricity for Others	328-330	
47	Transmission of Electricity by ISO/RTOs	331	None
48	Transmission of Electricity by Others	332	None
49	Miscellaneous General Expenses-Electric	335	
50	Depreciation and Amortization of Electric Plant	336-337	337 - None
51	Regulatory Commission Expenses	350-351	351 - None
52	Research, Development and Demonstration Activities	352-353	
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	None
55	Amounts included in ISO/RTO Settlement Statements	397	None
56	Purchase and Sale of Ancillary Services	398	
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	None
59	Electric Energy Account	401	
60	Monthly Peaks and Output	401	
61	Steam Electric Generating Plant Statistics	402-403	
62	Hydroelectric Generating Plant Statistics	406-407	None
63	Pumped Storage Generating Plant Statistics	408-409	None
64	Generating Plant Statistics Pages	410-411	None
65	Transmission Line Statistics Pages	422-423	
66	Transmission Lines Added During the Year	424-425	

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	12/31/2007	End of 2007/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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".

Stockholders' Reports Check appropriate box:

[X] Four copies will be submitted

[ ] No annual report to stockholders is prepared

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	12/31/2007	End of 2007/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jeffrey M. Stone
Chief Accounting Officer
412 S. Wilmington Street
Raleigh, NC 27601

Florida Power Corporation
299 First Avenue North
St. Petersburg, FL 33701

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Florida
July 18, 1899

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric service in the State of Florida

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

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	12/31/2007	End of 2007/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Florida Power Corporation is a wholly-owned subsidiary of Progress Energy, Inc., a North Carolina corporation.

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	12/31/2007	End of 2007/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	Chief Executive Officer and President	Jeffrey J. Lyash	2,556,924
2			
3	Executive Vice President and Chairman	William D. Johnson	7,744,448
4			
5	Executive Vice President and Chief Financial Officer	Peter M. Scott III	7,438,353
6			
7	Senior Vice President and Chief Nuclear Officer	C.S. Hinnant	4,655,224
8			
9	Senior Vice President	John R. McArthur	2,406,233
10			
11	Executive Vice President	Fred N. Day IV	3,372,185
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Schedule Page: 104 Line No.: 1 Column: a

Compensation information for the Chief Executive Officer (CEO) of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) along with PEF's Chief Financial Officer (CFO), the other three most highly paid executive officers who were serving at the end of 2007, and one individual who would have been included as one of our three most highly paid executives but for the fact that he retired from PEF before the end of 2007. 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 2007 received by the CEO, CFO, the three most highly paid executive officers who were serving at the end of 2007, and the one individual who would have been included as one of our three most highly paid executives but for the fact that he retired from PEF before the end of 2007, 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 officer among the various subsidiaries to which they provide services.

Schedule Page: 104 Line No.: 3 Column: a

See footnote at Line 1 Column A.

Schedule Page: 104 Line No.: 3 Column: c

See footnote at Line 1 Column C.

Schedule Page: 104 Line No.: 5 Column: a

See footnote at Line 1 Column A.

Schedule Page: 104 Line No.: 5 Column: c

See footnote at Line 1 Column C.

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

See footnote at Line 1 Column A. Officer retired effective January 1, 2008.

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. Officer retired effective July 1, 2007.

Schedule Page: 104 Line No.: 11 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	12/31/2007	End of 2007/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	Jeffrey A. Corbett, Senior Vice President	P.O. Box 1551, Raleigh, NC 27602
2	Fred N. Day, IV, Executive Vice President	P.O. Box 1551, Raleigh, NC 27602
3	William D. Johnson, Chairman	P.O. Box 1551, Raleigh, NC 27602
4	Jeffrey J. Lyash, President and CEO	299 First Avenue North, St. Petersburg, FL 33701
5	John R. McArthur, Senior Vice President	P.O. Box 1551, Raleigh, NC 27602
6	Robert B. McGehee, Chairman	Deceased
7	Peter M. Scott III, Executive Vice President and CFO	P.O. Box 1551, Raleigh, NC 27602
8	Lloyd M. Yates, President and CEO	P.O. Box 1551, Raleigh, NC 27602
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FOOTNOTE DATA

Schedule Page: 105 Line No.: 1 Column: a
Resigned from the Board effective December 31, 2007.

Schedule Page: 105 Line No.: 2 Column: a
Resigned from the Board effective June 30, 2007.

Schedule Page: 105 Line No.: 3 Column: a
Elected Chairman of the Board effective November 26, 2007.

Schedule Page: 105 Line No.: 6 Column: a
Deceased October 9, 2007.

Schedule Page: 105 Line No.: 8 Column: a
President and CEO of Carolina Power and Light Company. Elected to Board effective August 27, 2007.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2007	End of 2007/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, 2007 there were no important changes or additions to Franchise Rights.

   During the quarter ended June 30, 2007 there were no important changes or additions to Franchise Rights.

   During the quarter ended September 30, 2007 there were no important changes or additions to Franchise Rights.

   During the quarter ended December 31, 2007 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

   Effective June 29, 2007, Florida Power Corporation became a 12.5% owner of APOG, LLC, a newly-created LLC owned 25% each by affiliates of Southern Company, Duke Energy, and SCANA, and 12.5% by Carolina Power and Light.

3. PURCHASE OR SALE OF AN OPERATING UNIT OR SYSTEM

   None

4. IMPORTANT LEASEHOLDS

   During the quarter ended June 30, 2007, Florida Power Corporation, d/b/a Progress Energy Florida, Inc., recorded a capital lease obligation in the amount of $184 million for a tolling agreement that was entered into between Progress Energy Florida and Shady Hills Power Company, LLC, an unrelated party. The delivery term begins April 1, 2007 and ends April 30, 2024.

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 31, 2007, Florida Power Corporation did not issue nor redeem any commercial paper.

During the quarter ended June 30, 2007, Florida Power Corporation did not issue nor redeem any commercial paper.

During the quarter ended September 30, 2007, Florida Power Corporation issued $147,300,000 and redeemed $147,000,000 in commercial paper. The weighted average yield issued during the period was 5.451%.

On September 18, 2007, Florida Power Corporation d/b/a Progress Energy Florida, Inc., issued $250,000,000 First Mortgage Bonds, 5.80% Series due September 15, 2017.

On September 18, 2007, Florida Power Corporation d/b/a Progress Energy Florida, Inc., issued $500,000,000 First Mortgage Bonds, 6.35% Series due September 15, 2037.

During the quarter ended December 31, 2007, Florida Power Corporation did not issue nor redeem any commercial paper.

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 19, 2007, all non-bargaining unit employees received a 3.5% merit increase. Wages will increase approximately $19 million per year.

Effective November 26, 2007, all bargaining unit employees received a 3.0% 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 $3.4 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, 2007.

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, 2007.

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, 2007.

See Part I, Item 3. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Report on Form 10-K for the year-ended December 31, 2007.

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:

Sarah S. Rogers, VP	Removed 1/26/2007
Mark V. Wimberly, VP	Elected 2/19/2007
Daniel L. Roderick, VP	Elected 4/16/2007
Scott D. Self, VP	Elected 4/23/2007
Erik R. Hanson, VP	Removed 6/15/2007
David W. Sorrick, VP	Elected 6/18/2007
Charles M. Gates, VP	Removed 6/18/2007
E. Michael Williams, SVP	Removed 6/30/2007
Fred N. Day IV, EVP	Removed 6/30/2007
Bruce M. Baldwin, VP	Removed 7/1/2007
Lloyd M. Yates, SVP	Removed 7/1/2007
William D. Johnson, Grp. Pres.	Removed 7/11/2007
Lloyd M. Yates, Pres. and CEO	Elected 7/1/2007
Mark F. Mulhern, SVP	Elected 9/17/2007
Robert B. McGehee, Chairman	Removed 10/9/2007
William D. Johnson, EVP	Removed 10/12/2007
Scott D. Self, VP	Removed 11/2/2007
John Elnitsky, VP	Elected 11/12/2007
William D. Johnson, Chairman	Elected 11/26/2007
Jeffrey A. Corbett, SVP	Removed 12/31/2007
C.S. Hinnant, CNO & SVP	Removed 12/31/2007
Michael A. Lewis, VP	Removed 12/31/2007
Peter E. Toomey, VP	Elected 12/31/2007

Director Changes:

Fred N. Day IV	Removed 6/30/2007
David L. Burner	Removed 7/11/2007
James E. Bostic, Jr.	Removed 7/11/2007
Richard L. Daugherty	Removed 7/11/2007
Harris E. DeLoach, Jr.	Removed 7/11/2007
W. Steven Jones	Removed 7/11/2007
Robert W. Jones	Removed 7/11/2007
E. Marie McKee	Removed 7/11/2007
John H. Mullin, III	Removed 7/11/2007
Carlos A. Saladrigas	Removed 7/11/2007
Theresa M. Stone	Removed 7/11/2007
Alfred C. Tollison	Removed 7/11/2007
C. S. Hinnant	Elected 7/11/2007
John R. McArthur	Elected 7/11/2007
Lloyd M. Yates	Elected 7/11/2007
Peter M. Scott, III	Elected 7/11/2007
William D. Johnson	Elected 7/11/2007
Robert B. McGehee	Removed 10/9/2007
Jeffrey B. Corbett	Removed 12/31/2007

The Progress Energy board of directors implemented the approved succession plan for the CEO post on October 12, 2007. The board unanimously elected Bill Johnson as chairman of the board of directors, CEO and president of the Company, which took immediate effect. Bill Johnson replaced Bob McGehee, the former chairman and CEO, who died October 9, 2007 in England after suffering a stroke while in London on Company business.

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	12/31/2007	End of 2007/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

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	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	10,060,472,116	9,232,902,903
3	Construction Work in Progress (107)	200-201	1,191,510,032	641,485,881
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,251,982,148	9,874,388,784
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,540,773,297	4,401,159,420
6	Net Utility Plant (Enter Total of line 4 less 5)		6,711,208,851	5,473,229,364
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	5,036,739	12,481,913
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		5,432,526	610,437
9	Nuclear Fuel Assemblies in Reactor (120.3)		104,048,587	99,097,726
10	Spent Nuclear Fuel (120.4)		41,325,520	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	76,991,397	53,780,714
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		78,851,975	58,409,362
14	Net Utility Plant (Enter Total of lines 6 and 13)		6,790,060,826	5,531,638,726
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		10,324,516	10,338,328
19	(Less) Accum. Prov. for Depr. and Amort. (122)		4,346,753	3,815,226
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	28,663,433	0
24	Other Investments (124)		1,537,870	962,213
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		619,964,706	590,096,066
29	Special Funds (Non Major Only) (129)		220,570,036	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		99,419,541	2,114,653
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		976,133,349	599,696,034
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		17,473,015	21,649,999
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		3,580,742	0
39	Notes Receivable (141)		26,125	74,067
40	Customer Accounts Receivable (142)		278,710,573	274,738,966
41	Other Accounts Receivable (143)		24,045,585	18,877,119
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		10,406,159	8,139,226
43	Notes Receivable from Associated Companies (145)		148,792,311	0
44	Accounts Receivable from Assoc. Companies (146)		8,435,554	11,226,533
45	Fuel Stock (151)	227	245,349,474	239,606,898
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	201,489,836	188,558,542
49	Merchandise (155)	227	674,288	550,736
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	31,568,873	1,942,701

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	12/31/2007	End of 2007/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(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)
53	(Less) Noncurrent Portion of Allowances		28,663,433	0
54	Stores Expense Undistributed (163)	227	33,546,843	5,825,542
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		3,615,876	128,350,988
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		176,219	602,569
61	Accrued Utility Revenues (173)		58,931,935	54,880,718
62	Miscellaneous Current and Accrued Assets (174)		0	46,500,000
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		182,630,791	2,114,653
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		99,419,541	2,114,653
67	Total Current and Accrued Assets (Lines 34 through 66)		1,100,558,907	985,246,152
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		28,018,345	19,655,889
70	Extraordinary Property Losses (182.1)	230	15,658,702	89,985,218
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	268,239,736	382,576,666
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,401,428	2,861,010
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	9,063,123	9,409,719
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		24,853,429	27,021,114
82	Accumulated Deferred Income Taxes (190)	234	458,534,900	380,246,000
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		806,769,663	911,755,616
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		9,673,522,745	8,028,336,528

Schedule Page: 110 Line No.: 31 Column:

The prior year end balance for Long Term Portion of Derivative Instrument Assets- Hedges (176) is $2,114,653 more than reported in 2006 due to the change in presentation.

Schedule Page: 110 Line No.: 66 Column:

The prior year end balance for Long Term Portion of Derivative Instrument Assets- Hedges (176) is $2,114,653 more than reported in 2006 due to the change in presentation.

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 Rresubmission	12/31/2007	end of 2007/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)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	31,115	31,115
7	Other Paid-In Capital (208-211)	253	754,871,665	745,926,367
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)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	1,900,565,502	1,588,449,439
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-60	3,524
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)	-8,365,798	-1,535,018
16	Total Proprietary Capital (lines 2 through 15)		3,035,004,439	2,720,777,442
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,620,865,000	1,870,865,000
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	601,900,002	690,500,006
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,554,901	4,907,913
24	Total Long-Term Debt (lines 18 through 23)		3,219,210,101	2,556,457,093
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		223,554,534	53,436,969
27	Accumulated Provision for Property Insurance (228.1)		63,452,978	4,553,836
28	Accumulated Provision for Injuries and Damages (228.2)		17,687,819	12,783,989
29	Accumulated Provision for Pensions and Benefits (228.3)		263,008,776	233,539,828
30	Accumulated Miscellaneous Operating Provisions (228.4)		107,974,543	133,724,942
31	Accumulated Provision for Rate Refunds (229)		1,887,590	2,007,207
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		9,323,620	35,875,035
34	Asset Retirement Obligations (230)		314,585,846	298,680,863
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,001,475,706	774,602,669
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		450,787,742	276,543,387
39	Notes Payable to Associated Companies (233)		0	46,890,541
40	Accounts Payable to Associated Companies (234)		87,440,072	115,946,045
41	Customer Deposits (235)		184,625,135	167,609,006
42	Taxes Accrued (236)	262-263	-21,197,682	-21,326,851
43	Interest Accrued (237)		57,052,531	37,754,584
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)		22,825,452	15,160,392
48	Miscellaneous Current and Accrued Liabilities (242)		63,172,493	57,117,522
49	Obligations Under Capital Leases-Current (243)		7,124,768	926,770
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		47,603,424	124,960,289
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		9,323,620	35,875,035
54	Total Current and Accrued Liabilities (lines 37 through 53)		890,110,315	785,706,650
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,110,325	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	17,446,508	23,386,508
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	37,281,767	26,638,691
60	Other Regulatory Liabilities (254)	278	654,432,042	380,687,566
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	6,186,000	6,186,000
63	Accum. Deferred Income Taxes-Other Property (282)		441,093,000	440,451,000
64	Accum. Deferred Income Taxes-Other (283)		370,172,542	313,442,909
65	Total Deferred Credits (lines 56 through 64)		1,527,722,184	1,190,792,674
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		9,673,522,745	8,028,336,528

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	12/31/2007	End of 2007/Q4

STATEMENT OF INCOME

Quarterly

1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
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 (k) the quarter to date amounts for other utility function for the prior year quarter.
4. 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.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

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	4,692,523,332	4,559,906,728		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,243,675,914	2,733,541,096		
5	Maintenance Expenses (402)	320-323	165,685,317	151,274,324		
6	Depreciation Expense (403)	336-337	286,866,834	266,506,666		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	354,972	354,560		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	8,253,968	13,839,761		
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)		75,226,252	122,357,617		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		136,291,429	429,143,745		
13	(Less) Regulatory Credits (407.4)		126,981,192	114,809,864		
14	Taxes Other Than Income Taxes (408.1)	262-263	308,922,720	309,074,331		
15	Income Taxes - Federal (409.1)	262-263	155,587,614	203,726,041		
16	- Other (409.1)	262-263	28,773,090	33,701,977		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	298,702,301	243,555,011		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	337,343,771	285,230,725		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,940,000	-6,410,000		
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)		16,329,546	15,499,640		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,253,993,897	4,115,713,083		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		438,529,435	444,193,645		

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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
4,692,523,332	4,559,906,728					2
						3
3,243,675,914	2,733,541,096					4
165,685,317	151,274,324					5
286,866,834	266,506,666					6
354,972	354,560					7
8,253,968	13,839,761					8
-411,097	-411,097					9
75,226,252	122,357,617					10
						11
136,291,429	429,143,745					12
126,981,192	114,809,864					13
308,922,720	309,074,331					14
155,587,614	203,726,041					15
28,773,090	33,701,977					16
298,702,301	243,555,011					17
337,343,771	285,230,725					18
-5,940,000	-6,410,000					19
						20
						21
						22
						23
16,329,546	15,499,640					24
4,253,993,897	4,115,713,083					25
438,529,435	444,193,645					26

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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)		438,529,435	444,193,645		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility 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)		22,460,428	24,612,681		
34	(Less) Expenses of Nonutility Operations (417.1)		15,756,854	19,533,596		
35	Nonoperating Rental Income (418)		-430,005	-254,832		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-60	3,524		
37	Interest and Dividend Income (419)		7,384,528	22,285,651		
38	Allowance for Other Funds Used During Construction (419.1)		40,962,057	16,834,794		
39	Miscellaneous Nonoperating Income (421)		2,975,725	539,382		
40	Gain on Disposition of Property (421.1)		4,977,039	2,247,038		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		62,572,858	46,734,642		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		299	128,506		
44	Miscellaneous Amortization (425)	340	116,050			
45	Donations (426.1)	340	4,400,283	5,544,987		
46	Life Insurance (426.2)		-2,507,651	-2,437,454		
47	Penalties (426.3)		2,111,225			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		4,097,876	4,583,542		
49	Other Deductions (426.5)		1,162,301	1,111,780		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		9,380,383	8,931,361		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	103,766	159,173		
53	Income Taxes-Federal (409.2)	262-263	4,183,909	3,058,570		
54	Income Taxes-Other (409.2)	262-263	-173,270	763,420		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	592,324	-198,797		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	241,072	489,416		
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)		4,465,657	3,292,950		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		48,726,818	34,510,331		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		150,747,234	140,476,010		
63	Amort. of Debt Disc. and Expense (428)		4,364,116	4,239,516		
64	Amortization of Loss on Reaquired Debt (428.1)		2,167,686	2,167,686		
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)	340	2,199,543	1,483,069		
68	Other Interest Expense (431)	340	22,663,205	7,158,209		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,216,397	5,056,905		
70	Net Interest Charges (Total of lines 62 thru 69)		169,925,387	150,467,585		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		317,330,866	328,236,391		
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)		317,330,866	328,236,391		

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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		1,588,449,439	1,497,932,244
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Unrealized tax benefit/expense		-3,190,052	(1,553,420)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-3,190,052	(1,553,420)
10	FIN 48 Cumulative Impact		-512,951	
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-512,951	
16	Balance Transferred from Income (Account 433 less Account 418.1)		317,330,926	328,232,867
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			(234,650,392)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			(234,650,392)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,900,565,502	1,588,449,439
	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	12/31/2007	End of 2007/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)		1,900,565,502	1,588,449,439
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)		-60	3,524
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-60	3,524

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	12/31/2007	End of 2007/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)	317,330,866	328,236,391
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	287,520,679	267,789,359
5	Amortization of Limited and Electric Plant, Nuclear Fuel, Load Mgmt	17,287,043	33,690,216
6	Amortization of Debt Premium, expense and loss on acquisition	4,726,220	4,380,183
7	Other: (Gain) Loss on sale of assets, Other Adjustments to Net Income	76,209,698	34,929,531
8	Deferred Income Taxes (Net)	-38,649,772	-42,363,927
9	Investment Tax Credit Adjustment (Net)	-5,940,000	-6,410,000
10	Net (Increase) Decrease in Receivables	-19,979,624	-23,395,952
11	Net (Increase) Decrease in Inventory	-34,514,719	-134,500,051
12	Net (Increase) Decrease in Allowances Inventory	-29,626,172	7,670,904
13	Net Increase (Decrease) in Payables and Accrued Expenses	61,256,660	-16,425,496
14	Net (Increase) Decrease in Other Regulatory Assets	80,781,173	467,615,731
15	Net Increase (Decrease) in Other Regulatory Liabilities	111,536,590	70,661,106
16	(Less) Allowance for Other Funds Used During Construction	40,962,057	16,834,794
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote): Change in Current Assets	72,422,964	-46,569,903
19	Change in Other, Net	-60,059,749	-35,112,298
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	799,339,800	893,361,000
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,255,440,625	-744,166,999
27	Gross Additions to Nuclear Fuel	-43,883,010	-12,206,500
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-3,283,219	-1,342,931
30	(Less) Allowance for Other Funds Used During Construction	-40,962,057	-16,834,794
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,261,644,797	-740,881,636
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	7,415,214	3,413,076
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-149,116,150	-410,000
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-639,764,372	-625,424,547
45	Proceeds from Sales of Investment Securities (a)	639,764,372	625,424,547

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	12/31/2007	End of 2007/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): Company Owned Life Insurance	974,998	2,613,840
54	Other		-706
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,402,370,735	-735,265,426
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	739,269,819	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote): Increase in Intercompany Notes		34,068,081
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	71,051	
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	739,340,870	34,068,081
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-88,600,004	-48,299,998
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote): Decrease in Intercompany Notes	-46,794,314	
77			
78	Net Decrease in Short-Term Debt (c)		-102,000,000
79	Other		-125,586
80	Dividends on Preferred Stock	-1,511,859	-1,511,859
81	Dividends on Common Stock		-234,650,392
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	602,434,693	-352,519,754
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-596,242	-194,424,180
87			
88	Cash and Cash Equivalents at Beginning of Period	21,649,999	216,074,179
89			
90	Cash and Cash Equivalents at End of period	21,053,757	21,649,999

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 and (4) the classification of cost of removal obligations. 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 2007 were approximately $149 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 that do not separately meet the quantitative disclosure requirements as a separate 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) and 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 minority interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for minority interest 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 (generally 20 percent to 50 percent ownership), 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 (See Note 20). 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 13 for more information about our investments.

Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), 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.

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 2006 and 2005 have been reclassified to conform to the 2007 presentation. In addition, our 2007 presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under SFAS No. 95, "Statement of Cash Flows." Previously, we had provided separate disclosure of cash flows from continuing operations and discontinued operations. These changes in cash flow presentations had no impact on total cash and cash equivalents, net change in cash and cash equivalents, or results of operations.

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 for which we are the primary beneficiary in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46R, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51" (FIN 46R).

PROGRESS ENERGY

In addition to the variable interests listed below for PEC and PEF, we have interests through other subsidiaries in several variable interest entities for which we are not the primary beneficiary. These arrangements include investments in five limited liability partnerships and limited liability corporations. At December 31, 2007, the aggregate additional maximum loss exposure that we could be required to record in our income statement as a result of these arrangements was $6 million, which represents our net remaining investment in the entities. The creditors of these variable interest entities do not have recourse to our general credit in excess of the aggregate maximum loss exposure.

PEC

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). At December 31, 2007, the total assets of the two entities were $37 million, the majority of which are collateral for the entities' obligations and are included in miscellaneous other property and investments in the Consolidated Balance Sheet.

PEC has an interest in and consolidates a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. PEC has requested the necessary information to determine if the 17 partnerships are variable interest entities 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 in FIN 46R, paragraph 4(g), to the 17 partnerships. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the entities 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.

PEC also has an interest in one power plant resulting from long-term power purchase contracts. Our only significant exposure to variability from these 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 $39 million, $45 million and $44 million in 2007, 2006 and 2005, 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 power plant owner is a variable interest entity or to identify the primary beneficiary. The entity declined to provide us with the necessary financial information and PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the power plant. PEC believes that if it is determined to be the primary beneficiary of the entity, the effect of consolidating the entity 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 counterparty, the impact cannot be determined at this time.

PEC also has interests in several other variable interest entities for which PEC is not the primary beneficiary. These arrangements include investments in 21 limited liability partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. At December 31, 2007, the aggregate maximum loss exposure that PEC could be required to record on its income statement as a result of these arrangements totals $19 million, which primarily represents its net remaining investment in these entities. The creditors of these variable interest entities do not have recourse to the general credit of PEC in excess of the aggregate maximum loss exposure.

PEF

PEF has interests in four variable interest entities for which PEF is not the primary beneficiary. These arrangements include investments in one venture capital fund, one limited liability corporation, one building lease with a special-purpose entity and one operating lease with a special-purpose entity. At December 31, 2007, the aggregate maximum loss exposure that PEF could be required to record in its income statement as a result of these arrangements was $56 million. The majority of this exposure is related to a prepayment clause in the building lease and is not considered equity at risk. The creditors of these variable interest entities do not have recourse to the general credit of PEF in excess of the aggregate maximum loss exposure.

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 revenues earned when service has been delivered but not billed by the end of the accounting period, and diversified business revenues, which are generally recognized at the time products are shipped or as services are rendered. Customer prepayments are recorded as deferred revenue and recognized as revenues as the services are provided.

FUEL COST DEFERRALS

Fuel expense includes fuel costs or 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)	**2007**	2006	2005
Progress Energy	**$299**	$293	$258
PEC	**99**	94	91
PEF	**200**	199	167

STOCK-BASED COMPENSATION

Prior to July 2005, we accounted for stock-based compensation under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for our stock-based compensation costs. In addition, we followed the disclosure requirements contained in SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123), as amended by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." Effective July 1, 2005, we adopted the fair value recognition provisions of SFAS No. 123R, "Share-Based Payment" (SFAS No. 123R), for stock-based compensation utilizing the modified prospective transition method (See Note 10B).

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 that would otherwise not be capitalized under GAAP 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 (ARO) under SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), 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.

ASSET RETIREMENT OBLIGATIONS

We account for AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, in accordance with SFAS No. 143. 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 an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. In addition, effective December 31, 2005, we also adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), which clarified certain requirements of SFAS No. 143.

The adoption of SFAS No. 143 and FIN 47 had no impact on the income of the Utilities as the effects were offset by the establishment of regulatory assets and regulatory liabilities pursuant to SFAS No. 71 (See Note 7A) and in accordance with orders issued by the NCUC, the SCPSC and the FPSC.

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 5A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization 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. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended in December 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 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. During 2007, the NCUC approved

PEC's request to amortize the remaining 30 percent of the original estimated compliance costs during 2008 and 2009, with discretion to amortize up to $174 million in either year.

CASH AND CASH EQUIVALENTS

We consider cash and cash equivalents to include unrestricted cash on hand, cash in banks and temporary investments purchased with a 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. We value inventory of nonregulated subsidiaries at the lower of cost or market.

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to SFAS No. 71, 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.

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. Since 2002, Progress Energy tax benefits not related to acquisition interest expense had been allocated to profitable subsidiaries in accordance with an order under the Public Utilities Holding Company Act of 1935, as amended (PUHCA 1935). Except for the allocation of these Progress Energy tax benefits, income taxes are provided as if PEC and PEF filed separate returns. Due to the repeal of PUHCA 1935, effective February 8, 2006, we stopped allocating these tax benefits.

Deferred income taxes have been provided for temporary differences. These occur when there are differences between the 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. 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 on the Consolidated Statements of Income.

DERIVATIVES

We account for derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as assets or liabilities in the balance sheet and measure those instruments at fair value, unless the derivatives meet the SFAS No. 133 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 SFAS No. 133 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 SFAS No. 133 hedge criteria are met. 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 in accordance with SFAS No. 5, "Accounting for Contingencies" (SFAS No. 5). Under SFAS No. 5, contingent losses such as unfavorable results of litigation are recorded when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. Unless otherwise required by GAAP, we do not accrue 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 SFAS No. 5 have been met. 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. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. 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

As discussed in Note 9, we account for impairment of long-lived assets in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). 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 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.

SUBSIDIARY STOCK TRANSACTIONS

Gains and losses realized as a result of common stock sales by our subsidiaries are recorded in the Consolidated Statements of Income, except for any transactions that must be credited directly to equity in accordance with the provisions of Staff Accounting Bulletin No. 51, "Accounting for Sales of Stock by a Subsidiary."

2. NEW ACCOUNTING STANDARDS

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes"

Refer to Note 14 for information regarding our first quarter 2007 implementation of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48).

SFAS No. 157, "Fair Value Measurements"

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), which redefines 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." SFAS No. 157 establishes a framework for measuring fair value and a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. The effective date of SFAS No. 157 for us and the Utilities is January 1, 2008. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, which for us and the Utilities delays the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except for those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until January 1, 2009. We will implement SFAS No. 157 as of January 1, 2008, and will utilize the deferral provision of FSP No. FAS 157-2 for all nonfinancial assets and liabilities within its scope. We do not expect the adoption of SFAS No. 157 to have a material impact on our or the Utilities' financial position or results of operations.

SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115"

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115" (SFAS No. 159), which permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The decision about whether to elect the fair value option is applied on an instrument by instrument basis, is irrevocable (unless a new election date occurs) and is applied to the entire financial instrument. SFAS No. 159 is effective for us and the Utilities on January 1, 2008. We do not expect the adoption of SFAS No. 159 to have a material impact on our or the Utilities' financial position or results of operations.

FASB Staff Position FIN No. 39-1, An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts

FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" (FIN 39), specifies what conditions must be met for an entity to have the right to offset assets and liabilities in the balance sheet and clarifies when it is appropriate to offset amounts recognized for forward interest rate swap, currency swap, option and other conditional or exchange contracts. FIN 39 also permits offsetting of fair value amounts recognized for multiple contracts executed with the same counterparty under a master netting arrangement. On April 30, 2007, the FASB issued FASB Staff Position FIN No. 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts" (FSP FIN 39-1), which amends portions of FIN 39 to make certain terms consistent with those used in SFAS No. 133. FSP FIN 39-1 also amends FIN 39 to allow for the offsetting of fair value amounts for the right to reclaim collateral assets or liabilities arising from the same master netting arrangement as the derivative instruments. We will implement the FSP as of January 1, 2008, as a retrospective change in accounting principle for all financial statements presented. We and the Utilities currently offset fair value amounts recognized for derivative instruments under master netting arrangements. As allowed under FSP FIN 39-1, we and the Utilities will change our accounting policy effective January 1, 2008, and discontinue the offset of fair value amounts for such derivatives. We expect this change in policy to result in increases to total derivative assets and liabilities and accounts receivables and payables of $64 million as of adoption on January 1, 2008, but will have no impact on our or the Utilities' results of operations or equity.

SFAS No. 141R, "Business Combinations"

In December 2007, the FASB issued SFAS Statement No. 141R, "Business Combinations" (SFAS No. 141R), which introduces significant changes in the accounting for business acquisitions. SFAS No. 141R considerably broadens the definition of a "business" and a "business combination," which will result in an increased number of transactions or other events that will qualify as business combinations. This will affect us and the Utilities primarily in our assessment of variable interest entities ("VIEs"). SFAS No. 141R amends FIN 46R to clarify that the initial consolidation of a business that is a VIE is a business combination in which the acquirer should recognize and measure the fair value of the acquiree as a whole, and the assets acquired and liabilities assumed at their full fair values as of the date control is obtained, regardless of the percentage ownership in the acquiree or how the acquisition was achieved. Other significant changes include the expensing of all acquisition-related transaction costs and most acquisition-related restructuring costs, the fair value remeasurement of certain earn-out arrangements and the discontinuance of the expense at acquisition of acquired-in-process research and development. SFAS No. 141R is effective for us for business combinations for which the acquisition date is on or after January 1, 2009. Earlier application is prohibited. We do not expect the adoption of SFAS No. 141R to have a material impact on our or the Utilities' financial position or results of operations.

SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51"

In conjunction with the issuance of SFAS No. 141R, in December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51" (SFAS No. 160) which introduces significant changes in the accounting for noncontrolling interests in a partially owned consolidated subsidiary. SFAS No. 160 also changes the accounting for and reporting for the deconsolidation of a subsidiary. SFAS No. 160 requires that a noncontrolling interest in a consolidated subsidiary be displayed in the consolidated statement of financial position as a separate component of equity rather than as a "mezzanine" item between liabilities and equity. SFAS No. 160 also requires that earnings attributed to the noncontrolling interests be reported as part of consolidated earnings, and requires disclosure of the attribution of consolidated earnings to the controlling and noncontrolling interests on the face of the consolidated income statement. SFAS No. 160 must be adopted concurrently with the effective date of SFAS No. 141R, which for us is January 1, 2009. We do not expect the adoption of SFAS No. 160 to have a material impact on our or the Utilities' financial position or results of operations.

3. DIVESTITURES

A. CCO – GEORGIA OPERATIONS

On March 9, 2007, our subsidiary, Progress 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. Assets divested include approximately 1,900 MW of gas-fired generation assets in Georgia. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated after-tax loss of $226 million in December 2006. Based on the terms of the final agreement and post-closing adjustments, during the year ended December 31, 2007, we reversed $18 million after-tax of the impairment recorded in 2006.

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 represents 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 represents 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.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of CCO as discontinued operations. Interest expense has been 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 years ended December 31, 2007, 2006 and 2005 was $11 million, $36 million and $39 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. After-tax depreciation expense during each of the years ended December 31, 2006 and 2005 was $14 million. Results of discontinued operations for CCO for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$407**	$754	$627
Loss before income taxes	**$(449)**	$(92)	$(93)
Income tax benefit	**166**	35	39
Net loss from discontinued operations	**(283)**	(57)	(54)
Gain (loss) on disposal of discontinued operations, including income tax benefit of $7 and $123, respectively	**18**	(226)	–
Loss from discontinued operations	**$(265)**	$(283)	$(54)

B. TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

On December 24, 2007, we signed an agreement to sell coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. Terminals was previously a component of our former Coal and Synthetic Fuels segment. The terminals have a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale are expected to be used for general corporate purposes. We expect this transaction to close by the end of the first quarter of 2008.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of Terminals as discontinued operations. Interest expense has been 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 years ended December 31, 2007, 2006 and 2005 was $1 million, $1 million and $3 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in November 2007. After-tax depreciation expense during each of the years ended December 31, 2007, 2006 and 2005 was $2 million, $4 million and $7 million, respectively.

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels (Synthetic Fuels) as defined under Section 29 of the Code. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. Synthetic fuels are generally not economical to produce and sell absent the credits. On September 14, 2007, we idled production of synthetic fuels at our majority-owned synthetic fuels facilities due to the high level of oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007, and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. 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. In accordance with the provisions of SFAS No. 144, a long-lived asset is abandoned when it ceases to be used. The accompanying consolidated income statements have been restated for all periods presented to reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Results of discontinued operations for the years ended December 31 for Terminals and Synthetic Fuels were as follows:

(in millions)	2007	2006	2005
Revenues	**$1,126**	$847	$1,220
Earnings (loss) before income taxes and minority interest	**$2**	$(179)	$(171)
Income tax benefit, including tax credits	**64**	135	336
Minority interest share of losses	**17**	7	33
Net earnings (loss) from discontinued operations	**$83**	$(37)	$198

C. NATURAL GAS DRILLING AND PRODUCTION

On October 2, 2006, we sold our natural gas drilling and production business (Gas) for approximately $1.1 billion in net proceeds. Gas included Winchester Production Company, Ltd. (Winchester Production), Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels. Proceeds from the sale have been used primarily to reduce holding company debt and for other corporate purposes.

Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006. We recorded an after-tax loss of $2 million during the year ended December 31, 2007, primarily related to working capital adjustments.

The accompanying consolidated financial statements reflect the operations of Gas as discontinued operations. Interest expense has been 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 each of the years ended December 31, 2006, and 2005 was $13 million. We ceased recording depreciation upon classification of the assets as discontinued operations in July 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $16 million and $26 million, respectively. Results of discontinued operations for Gas for the years ended December 31 were as follows:

(in millions)	2007	2006	2005
Revenues	**$–**	$192	$159
Earnings before income taxes	**$–**	$135	$73
Income tax benefit (expense)	**4**	(53)	(25)
Net earnings from discontinued operations	**4**	82	48
(Loss) gain on disposal of discontinued operations, including income tax benefit (expense) of $1 and $(188), respectively	**(2)**	300	–
Earnings from discontinued operations	**$2**	$382	$48

D. CCO – DESOTO AND ROWAN GENERATION FACILITIES

On May 2, 2006, our board of directors approved a plan to divest of two subsidiaries of PVI, DeSoto County Generating Co., LLC (DeSoto) and Rowan County Power, LLC (Rowan). DeSoto owned a 320 MW dual-fuel combustion turbine electric generation facility in DeSoto County, Fla., and Rowan owned a 925 MW dual-fuel combined cycle and combustion turbine electric generation facility in

Rowan County, N.C. On May 8, 2006, we entered into definitive agreements to sell DeSoto and Rowan, including certain existing power supply contracts, to Southern Power Company, a subsidiary of Southern Company, for gross purchase prices of approximately $80 million and $325 million, respectively. We used the proceeds from the sales to reduce debt and for other corporate purposes.

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. Based on the gross proceeds associated with the sales, we recorded an after-tax loss on disposal of $67 million during the year ended December 31, 2006.

The accompanying consolidated financial statements reflect the operations of DeSoto and Rowan as discontinued operations. Interest expense has been 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 years ended December 31, 2006, and 2005 was $6 million and $13 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in May 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $3 million and $8 million, respectively. Results of discontinued operations for DeSoto and Rowan for the years ended December 31 were as follows:

(in millions)	2006	2005
Revenues	$64	$67
Earnings before income taxes	$15	$5
Income tax expense	(5)	(2)
Net earnings from discontinued operations	10	3
Loss on disposal of discontinued operations, including income tax benefit of $37	(67)	–
(Loss) earnings from discontinued operations	$(57)	$3

E. PROGRESS TELECOM, LLC

On March 20, 2006, we completed the sale of Progress Telecom, LLC (PT LLC) to Level 3 Communications, Inc. (Level 3). We received gross proceeds comprised of cash of $69 million and approximately 20 million shares of Level 3 common stock valued at an estimated $66 million on the date of the sale. Our net proceeds from the sale of approximately $70 million, after consideration of minority interest, were used to reduce debt. Prior to the sale, we had a 51 percent interest in PT LLC. See Note 20 for a discussion of the subsequent sale of the Level 3 stock in 2006.

Based on the net proceeds associated with the sale and after consideration of minority interest, we recorded an after-tax net gain on disposal of $28 million during the year ended December 31, 2006.

The accompanying consolidated financial statements reflect the operations of PT LLC as discontinued operations. Interest expense has been 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 was $1 million for the year ended December 31, 2005. We ceased recording depreciation upon classification of the assets as discontinued operations in January 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $1 million and $8 million, respectively. Results of discontinued operations for PT LLC for the years ended December 31 were as follows:

(in millions)	2006	2005
Revenues	$18	$76
Earnings before income taxes and minority interest	$7	$11
Income tax expense	(4)	(3)
Minority interest share of earnings	(5)	(4)
Net (loss) earnings from discontinued operations	(2)	4
Gain on disposal of discontinued operations, including income tax expense of $8 and minority interest of $35	28	–
Earnings from discontinued operations	$26	$4

In connection with the sale, PEC and PEF provided indemnification against costs associated with certain asset performances to Level 3. See general discussion of guarantees at Note 22C. The ultimate resolution of these matters could result in adjustments to the gain on sale in future periods.

F. DIXIE FUELS AND OTHER FUELS BUSINESS

On March 1, 2006, we sold Progress Fuels' 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units. Dixie Fuels primarily transports coal from the lower Mississippi River to Progress Energy's Crystal River facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels during the year ended December 31, 2006. During the year ended December 31, 2007, we recorded an additional gain of $2 million primarily related to the expiration of indemnifications.

The accompanying consolidated financial statements reflect Dixie Fuels and the other fuels business as discontinued operations. Interest expense has been 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 was $1 million for each of the years ended December 31, 2006, and 2005. We ceased recording depreciation upon classification of the assets as discontinued operations. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $1 million and $2 million, respectively. Results of discontinued operations for Dixie Fuels and other fuels businesses for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$–**	$20	$32
Earnings before income taxes	**$–**	$11	$8
Income tax expense	**–**	(4)	(3)
Net earnings from discontinued operations	**–**	7	5
Gain on disposal of discontinued operations, including income tax expense of $1 and $1, respectively	**2**	2	–
Earnings from discontinued operations	**$2**	$9	$5

G. COAL MINING BUSINESSES

Progress Fuels owned five subsidiaries engaged in the coal mining business. These businesses were previously included in our former Coal and Synthetic Fuels business segment. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an after-tax loss of $10 million on the sale of these assets.

On December 24, 2007, we signed an agreement to sell the remaining net assets of the coal mining business for gross cash proceeds of $23 million. These assets include Powell Mountain Coal Co. and Dulcimer Land Co., which consist of about 30,000 acres in Lee

County, Va. and Harlan County, Ky. The property contains an estimated 40 million tons of high quality coal reserves. We expect this transaction to close by the end of the first quarter of 2008.

The accompanying consolidated financial statements reflect the coal mining operations as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of the coal mines, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007, 2006 and 2005 was $1 million, $1 million and $3 million, respectively. We ceased recording depreciation expense upon classification of the coal mining operations as discontinued operations in November 2005. After-tax depreciation expense during the year ended December 31, 2005, was $10 million. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$28**	$84	$184
Loss before income taxes	**$(17)**	$(11)	$(16)
Income tax benefit	**6**	7	5
Net loss from discontinued operations	**(11)**	(4)	(11)
Loss on disposal of discontinued operations, including income tax benefit of $16	**–**	(10)	–
Loss from discontinued operations	**$(11)**	$(14)	$(11)

H. PROGRESS RAIL

On March 24, 2005, we completed the sale of Progress Rail Services Corporation (Progress Rail) to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Cash proceeds from the sale were approximately $429 million, consisting of $405 million base proceeds plus a working capital adjustment. Proceeds from the sale were used to reduce debt.

Based on the gross proceeds associated with the sale of $429 million, we recorded an estimated after-tax loss on disposal of $25 million during the year ended December 31, 2005. During the year ended December 31, 2006, we recorded an additional after-tax loss on disposal of $6 million in connection with guarantees and indemnifications provided by Progress Fuels and Progress Energy for certain legal, tax and environmental matters to One Equity Partners LLC. The ultimate resolution of these matters could result in adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

The accompanying consolidated financial statements reflect the operations of Progress Rail as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of Progress Rail, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the year ended December 31, 2005, was $4 million. We ceased recording depreciation upon classification of Progress Rail as discontinued operations in February 2005. After-tax depreciation expense during the year ended December 31, 2005, was $3 million. Results of discontinued operations for Progress Rail for the years ended December 31 were as follows:

(in millions)	2006	2005
Revenues	$–	$358
Earnings before income taxes	$–	$8
Income tax expense	–	(3)
Net earnings from discontinued operations	–	5
Loss on disposal of discontinued operations, including income tax (expense) benefit of $(6) and $15, respectively	(6)	
Loss from discontinued operations	$(6)	$(20)

I. NET ASSETS TO BE DIVESTED

At December 31, 2007, the assets and liabilities of Terminals and the remaining assets and liabilities of the coal mining operations were included in net assets to be divested. At December 31, 2006, the assets and liabilities of CCO, Terminals, the remaining coal mining operations and other fuels businesses were included in net assets to be divested. The major balance sheet classes included in assets and liabilities to be divested in the Consolidated Balance Sheets were as follows:

(in millions)	**December 31, 2007**	December 31, 2006
Accounts receivable	**$–**	$44
Inventory	**6**	56
Other current assets	**2**	45
Property, plant and equipment, net	**38**	595
Other assets	**6**	226
Assets to be divested	**$52**	$966
Accounts payable	**$–**	$43
Accrued expenses	**3**	179
Long-term liabilities	**5**	26
Liabilities to be divested	**$8**	$248

J. CEREDO SYNTHETIC FUELS INTERESTS

On March 30, 2007, our Progress Fuels subsidiary disposed of its 100 percent ownership interest in Ceredo Synfuel LLC (Ceredo), a subsidiary that produces and sells 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 non-recourse note receivable of $54 million. Payments on the note are due as we produce and sell qualifying 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 in 2007 and $5 million in 2008. The total amount of proceeds is subject to adjustment once the final value of the 2007 Section 29/45K credits is known. The note bears interest at a rate equal to the three-month London Inter Bank Offering Rate (LIBOR) rate plus 1%. The estimated fair value of the note at the inception of the transaction was $48 million.

Pursuant to the terms of the disposal agreement, the buyer had the right to unwind the transaction if an Internal Revenue Service (IRS) reconfirmation private letter ruling was not received by November 9, 2007, or if certain adverse changes in tax law, as defined in the agreement, occurred before November 19, 2007. The IRS reconfirmation private letter ruling was received on October 29, 2007, and no adverse change in tax law occurred prior to November 19, 2007. As of December 31, 2007, due to indemnification provisions discussed below, we recorded losses on disposal of $3 million based on the estimated value of the 2007 Section 29/45K tax credits. The operations of Ceredo have been reclassified to discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3B.

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 remained the primary beneficiary of Ceredo and continued to consolidate Ceredo in accordance with FIN 46R, but recorded a 100 percent minority interest. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer. The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods. See general discussion of guarantees at Note 22C.

K. WINTER PARK DISTRIBUTION ASSETS

As discussed in Note 7C, PEF sold certain electric distribution assets to Winter Park, Fla. (Winter Park), on June 1, 2005.

L. SYNTHETIC FUELS PARTNERSHIP INTERESTS

In two June 2004 transactions, Progress Fuels sold a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of its synthetic fuels facilities. Substantially all proceeds from the sales were received over time, which is typical of such sales in the industry. Gains from the sales were recognized on a cost-recovery basis. The book value of the interests sold totaled approximately $5 million. We recognized gains on these transactions of $4 million and $30 million in the years ended December 31, 2006, and 2005, respectively. In 2007, due to the increase in the price of oil that limits synthetic fuels tax credits, we did not record any additional gains. The operations of Colona have been reclassified to discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3B.

4. ACQUISITIONS

In May 2005, Winchester Production, an indirectly wholly owned subsidiary of Progress Fuels, acquired a 50 percent interest in 11 natural gas producing wells and proven reserves of approximately 25 billion cubic feet equivalent from a privately owned company headquartered in Texas. In addition to the natural gas reserves, the transaction also included a 50 percent interest in the gas gathering systems related to these reserves. The total cash purchase price for the transaction was $46 million. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2005. In 2006, we sold our 50 percent interest in the wells, reserves and gas gathering system as part of our transaction with EXCO Resources, Inc. (See Note 3C).

5. 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 2007	2006	PEC 2007	2006	PEF 2007	2006
Production plant	7-43	**$13,765**	$12,685	**$8,968**	$8,422	**$4,612**	$4,078
Transmission plant	17-75	**2,684**	2,509	**1,361**	1,300	**1,323**	1,209
Distribution plant	13-55	**7,676**	7,351	**4,147**	3,992	**3,529**	3,359
General plant and other	5-35	**1,202**	1,198	**641**	642	**561**	556
Utility plant in service		**$25,327**	$23,743	**$15,117**	$14,356	**$10,025**	$9,202

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 12C).

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 8.8%, 8.7% and 5.6% in 2007, 2006 and 2005, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8%, 8.8% and

7.8% in 2007, 2006 and 2005, respectively.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4%, 2.3% and 2.2% in 2007, 2006 and 2005, respectively. The depreciation provisions related to utility plant were $560 million, $533 million and $477 million in 2007, 2006 and 2005, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 7B).

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, for the years ended December 31, 2007, 2006 and 2005 was $139 million, $140 million and $136 million, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income.

PEC's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.1% for 2007, 2006 and 2005. The depreciation provisions related to utility plant were $303 million, $294 million and $286 million in 2007, 2006 and 2005, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), 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%, 2.7% and 2.3% in 2007, 2006 and 2005, respectively. The depreciation provisions related to utility plant were $257 million, $239 million and $191 million in 2007, 2006 and 2005, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D) and regulatory approved expenses (See Notes 7 and 21).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the DOE and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2007, 2006 and 2005 was $110 million, $109 million and $107 million, respectively, for PEC and $29 million, $31 million and $29 million, respectively, for PEF. These costs were included in fuel used for electric generation in the Statements of Income.

B. DIVERSIFIED BUSINESS PROPERTY

Net diversified business property is included in miscellaneous other property and investments on our and PEC's Consolidated Balance Sheets. Diversified business property excludes amounts reclassified as assets to be divested (See Note 3I).

Progress Energy

The balances of diversified business property at December 31 are listed below, with a range of depreciable lives for each:

(in millions)	**2007**	2006
Equipment (3-25 years)	**$6**	$10
Land and mineral rights	**–**	1
Buildings and plants (5-40 years)	**9**	47
Accumulated depreciation	**(9)**	(50)
Diversified business property, net	**$6**	$8

Diversified business depreciation expense was $3 million, $2 million and $4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

PEC

Net diversified business property was $6 million at December 31, 2007 and $7 million at December 31, 2006. These amounts consist primarily of buildings and equipment that are being depreciated over periods ranging from 10 to 40 years. Accumulated depreciation was $2 million at both December 31, 2007 and December 31, 2006. Diversified business depreciation expense was less than $1 million each in 2007, 2006 and 2005.

C. 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 above 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:

2007 (in millions) Subsidiary	**Facility**	**Company Ownership Interest**	**Plant**	**Accumulated**	**Construction Work in Progress**
PEC	**Mayo**	**83.83%**	**$519**	**$270**	**$128**
PEC	**Harris**	**83.83%**	**3,175**	**1,581**	**21**
PEC	**Brunswick**	**81.67%**	**1,647**	**959**	**16**
PEC	**Roxboro Unit 4**	**87.06%**	**634**	**164**	**39**
PEF	**Crystal River Unit 3**	**91.78%**	**817**	**450**	**177**
PEF	**Intercession City Unit P11**	**66.67%**	**23**	**9**	**–**

2006 (in millions) Subsidiary	Facility	Company Ownership Interest	Plant	Accumulated	Construction Work in Progress
PEC	Mayo	83.83%	$517	$263	$–
PEC	Harris	83.83%	3,159	1,489	18
PEC	Brunswick	81.67%	1,632	941	15
PEC	Roxboro Unit 4	87.06%	356	163	1
PEF	Crystal River Unit 3	91.78%	811	452	76
PEF	Intercession City Unit P11	66.67%	23	7	–

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.

D. ASSET RETIREMENT OBLIGATIONS

At December 31, 2007 and 2006, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant, net of accumulated depreciation for PEC, totaled $29 million and $30 million, respectively. No costs related to nuclear decommissioning of irradiated plant were recorded at December 31, 2007 and 2006 at PEF. At December 31, 2007 and 2006, additional PEF-related asset retirement costs, net of accumulated depreciation, of $121 million and $126 million, respectively, were recorded at Progress Energy as purchase accounting adjustments when we purchased Florida Progress Corporation (Florida Progress) in 2000. The fair value of funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $804 million and $735 million at December 31, 2007 and 2006, respectively, for PEC and $580 million and $552 million, respectively, for PEF. Net nuclear decommissioning trust 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 2007, 2006 and 2005. 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 are not SFAS No. 143 AROs, which are included in depreciation and amortization expense, were $96 million, $96 million and $90 million in 2007, 2006 and 2005, respectively, for PEC and $30 million, $27 million and $78 million in 2007, 2006 and 2005, respectively, for PEF.

During 2005, PEF performed a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study decreased the rates used to calculate cost of removal expense with a resulting decrease of approximately $55 million in 2006.

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)	**2007**	2006	**2007**	2006	**2007**	2006
Removal costs	**$1,410**	$1,341	**$794**	$727	**$616**	$614
Nonirradiated decommissioning costs	**141**	137	**80**	76	**61**	61
Dismantlement costs	**125**	124	**–**	–	**125**	124
Non-ARO cost of removal	**$1,676**	$1,602	**$874**	$803	**$802**	$799

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC's most recent site-specific estimates of decommissioning costs were developed in 2004, using 2004 cost factors, and are 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 2004 dollars, were $569 million for Unit No. 2 at Robinson Nuclear Plant (Robinson), $418 million for Brunswick Nuclear Plant (Brunswick) Unit No. 1, $444 million for Brunswick Unit No. 2 and $775 million 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. NRC operating licenses held by PEC currently expire in July 2030, December 2034 and September 2036 for Robinson and Brunswick Units No. 2 and No. 1, respectively. The NRC operating license held by PEC for Harris currently expires in October 2026. An application to extend this license 20 years was submitted in the fourth quarter of 2006. Based on updated assumptions, in 2005 PEC further reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $14 million and $49 million, respectively.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF filed a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) with the FPSC on April 29, 2005, as part of PEF's base rate filing. 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 2005 dollars, is $614 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. The NRC operating license held by PEF for CR3 currently expires in December 2016. We expect to submit an application requesting a 20-year extension of this license in the first quarter of 2009. As part of this new estimate and assumed license extension, PEF reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $36 million and $94 million, respectively. In addition, we reduced PEF-related asset retirement costs, net of accumulated depreciation, by an additional $53 million at Progress Energy. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of a previous base rate agreement, and the base rate agreement resulting from a base rate proceeding in 2005 continues that suspension. 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 filed an updated fossil dismantlement study with the FPSC on April 29, 2005, as part of its base rate filing. PEF's reserve for fossil plant dismantlement was approximately $146 million and $145 million at December 31, 2007 and 2006, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended through December 2005 under the terms of PEF's previous base rate agreement. The base rate agreement resulting from a base rate proceeding in 2005 continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants (See Note 7C).

Upon implementation of FIN 47 as of December 31, 2005, the Utilities recognized additional ARO liabilities for asbestos abatement costs (See Note 1D).

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.

Our nonregulated AROs relate to our abandoned synthetic fuels operations. The related asset retirement costs, net of accumulated depreciation, totaled $1 million at December 31, 2006, and none at December 31, 2007.

The following table presents the changes to the AROs during the years ended December 31, 2007 and 2006. Revisions to prior estimates of the PEC regulated ARO are related to remeasuring the nuclear decommissioning costs of irradiated plants to take into account updated site-specific decommissioning cost studies, which are required by the NCUC every five years. Revisions to prior estimates of the PEF regulated ARO are related to the updated cost estimate for nuclear decommissioning described above.

	Progress Energy			
(in millions)	Regulated	Nonregulated	PEC	PEF
Asset retirement obligations at January 1, 2006	$1,239	$–	$949	$290
Accretion expense	72	–	57	15
Remediation	(2)	1	(2)	–
Revisions to prior estimates	(6)	–	–	(6)
Asset retirement obligations at December 31, 2006	1,303	1	1,004	299
Accretion expense	**75**	–	**59**	**16**
Remediation	–	**(1)**	–	–
Asset retirement obligations at December 31, 2007	**$1,378**	**$–**	**$1,063**	**$315**

E. 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 NEIL, following a 12-week deductible period, for 52 weeks in the amount of $4 million per week at the Brunswick, Harris and Robinson plants, and $5 million per week at the Crystal River plant. 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 $34 million with respect to the primary coverage, $37 million with respect to the decontamination, decommissioning and excess property coverage, and $24 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, 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 $10.760 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 $100 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 $15 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 31, 2008.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.200 billion for non-certified 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).

6. CURRENT ASSETS

A. RECEIVABLES

Income tax receivables and interest income receivables are not included in receivables. These amounts are included in prepaids and other current assets on the Consolidated Balance Sheets. At December 31 receivables were comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Trade accounts receivable	**$586**	$628	**$291**	$285	**$264**	$288
Unbilled accounts receivable	**220**	227	**156**	157	**59**	55
Notes receivable	**67**	57	**–**	–	**–**	–
Derivatives accounts receivable	**247**	–	**–**	–	**13**	–
Other receivables	**46**	46	**31**	36	**13**	5
Allowance for doubtful receivables	**(29)**	(28)	**(6)**	(5)	**(10)**	(8)
Total receivables	**$1,137**	$930	**$472**	$473	**$339**	$340

B. INVENTORY

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Fuel for production	**$455**	$470	**$210**	$230	**$245**	$240
Inventory for sale	**–**	2	**–**	–	**–**	–
Materials and supplies	**520**	442	**284**	247	**236**	194
Emission allowances	**19**	22	**16**	20	**3**	2
Total inventory	**$994**	$936	**$510**	$497	**$484**	$436

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits for Progress Energy of $65 million and $44 million at December 31, 2007 and 2006, respectively, and PEC of $44 million at December 31, 2007 and 2006.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits for Progress Energy, PEC and PEF of $32 million, $3 million and $29 million, respectively, at December 31, 2007. Progress Energy, PEC and PEF did not have any long-term emission allowance amounts at December 31, 2006.

7. REGULATORY MATTERS

A. REGULATORY ASSETS AND LIABILITIES

As regulated entities, the Utilities are subject to the provisions of SFAS No. 71. 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 SFAS No. 71 could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS No. 71 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 could result in an impairment of utility plant assets as determined pursuant to SFAS No. 144.

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

Progress Energy

(in millions)	2007	2006
Deferred fuel cost – current (Note 7B)	**$154**	$196
Deferred fuel cost – long-term (Note 7B)	**114**	114
Deferred impact of ARO – PEC (Note 1D)	**294**	282
Income taxes recoverable through future rates (Note 14)	**141**	114
Loss on reacquired debt (Note 1D)	**43**	46
Storm deferral (Notes 7B and 7C)	**22**	102
Postretirement benefits (Note 16)	**212**	373
Derivative mark-to-market adjustment (Note 17A)	**–**	78
Environmental (Notes 7B, 7C and 21A)	**40**	72
Investment in GridSouth (Note 7D)	**22**	–
Other	**43**	50
Total long-term regulatory assets	**931**	1,231
Deferred fuel cost – current (Note 7C)	**(154)**	(63)
Deferred energy conservation cost and other current regulatory liabilities	**(19)**	(13)
Total current regulatory liabilities	**(173)**	(76)
Non-ARO cost of removal (Note 5D)	**(1,676)**	(1,602)
Deferred impact of ARO – PEF (Note 1D)	**(226)**	(221)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(351)**	(330)
Clean Smokestacks Act compliance (Note 7B)	**–**	(333)
Derivative mark-to-market adjustment (Note 17A)	**(185)**	–
Storm reserve (Note 7C)	**(63)**	(2)
Other	**(38)**	(55)
Total long-term regulatory liabilities	**(2,539)**	(2,543)
Net regulatory liabilities	**$(1,627)**	$(1,192)

PEC

(in millions)	**2007**	2006
Deferred fuel cost – current (Note 7B)	**$148**	$196
Deferred fuel cost – long-term (Note 7B)	**114**	114
Deferred impact of ARO (Note 1D)	**294**	282
Income taxes recoverable through future rates (Note 14)	**51**	50
Loss on reacquired debt (Note 1D)	**18**	19
Storm deferral (Note 7B)	**6**	12
Postretirement benefits (Note 16)	**126**	243
Environmental (Note 7B)	**10**	15
Investment in GridSouth (Note 7D)	**22**	–
Other	**38**	42
Total long-term regulatory assets	**679**	777
Non-ARO cost of removal (Note 5D)	**(874)**	(803)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(188)**	(171)
Derivative mark-to-market adjustment (Note 17A)	**(19)**	–
Clean Smokestacks Act compliance (Note 7B)	**–**	(333)
Other	**(16)**	(13)
Total long-term regulatory liabilities	**(1,097)**	(1,320)
Net regulatory liabilities	**$(270)**	$(347)

PEF

(in millions)	**2007**	2006
Deferred fuel cost – current (Note 7C)	**$6**	$–
Storm deferral (Note 7C)	**16**	90
Income taxes recoverable through future rates (Note 14)	**90**	64
Loss on reacquired debt (Note 1D)	**25**	27
Postretirement benefits (Note 16)	**86**	130
Derivative mark-to-market adjustment (Note 17A)	**–**	78
Environmental (Notes 7C and 21A)	**30**	57
Other	**5**	8
Total long-term regulatory assets	**252**	454
Deferred fuel cost – current (Note 7C)	**(154)**	(63)
Deferred energy conservation cost and other current regulatory liabilities	**(19)**	(13)
Total current regulatory liabilities	**(173)**	(76)
Non-ARO cost of removal (Note 5D)	**(802)**	(799)
Deferred impact of ARO (Note 1D)	**(96)**	(88)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(163)**	(159)
Derivative mark-to-market adjustment (Note 17A)	**(166)**	–
Storm reserve (Note 7C)	**(63)**	(2)
Other	**(26)**	(43)
Total long-term regulatory liabilities	**(1,316)**	(1,091)
Net regulatory liabilities	**$(1,231)**	$(713)

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 anticipate recovering long-term deferred fuel costs in 2009 and loss on reacquired debt over the applicable lives of the debt. We expect to fully recover our regulatory assets and refund our regulatory liabilities through customer rates under current regulatory practice.

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 (ROE) of 12.75 percent. In June 2002, the North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxides (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 significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. For the years ended December 31, 2007, 2006 and 2005, PEC recognized amortization of $34 million, $140 million and $147 million, respectively, and recognized $569 million in cumulative amortization through December 31, 2007.

On March 23, 2007, PEC filed a petition with the NCUC requesting that it be allowed to amortize the remaining 30 percent (or $244 million) of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, with discretion to amortize up to $174 million in either year. Additionally, among other things, PEC requested that the NCUC allow PEC to include in its rate base those eligible compliance costs exceeding the original estimated compliance costs and that PEC be allowed to accrue AFUDC on all eligible compliance costs in excess of the original estimated compliance costs. PEC also requested that any prudency review of PEC's environmental compliance costs be deferred until PEC's next ratemaking proceeding in which PEC seeks to adjust its base rates. On October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, the Carolina Utility Customers Associations (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis, with the NCUC indicating that it intended to initiate a review in 2009 to consider all reasonable alternatives and proposals related to PEC's recovery of its Clean Smokestacks Act compliance costs in excess of the original estimated costs of $813 million. Additionally, the NCUC ordered that no portion of Clean Smokestacks Act compliance costs directly assigned, allocated or otherwise attributable to another jurisdiction shall be recovered from PEC's retail North Carolina customers, even if recovery of these costs is disallowed or denied, in whole or in part, in another jurisdiction. We cannot predict the outcome of PEC's recovery of eligible compliance costs exceeding the original estimated compliance costs.

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

FUEL COST RECOVERY

On May 2, 2007, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers. PEC asked the SCPSC to approve a $12 million increase in fuel rates for under-recovered fuel costs associated with prior year settlements and to meet future expected fuel costs. On June 27, 2007, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceedings. The settlement agreement resolved all issues and provided for a $12 million increase in fuel rates. Effective July 1, 2007, residential electric bills increased by $1.83 per 1,000 kilowatt-hours (kWh), or 1.9 percent, for fuel cost recovery. At December

31, 2007, PEC's South Carolina deferred fuel balance was $21 million.

On June 8, 2007, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. PEC asked the NCUC to approve a $48 million increase in fuel rates. On September 25, 2007, the NCUC approved PEC's petition. The increase took effect October 1, 2007, and increased residential electric bills by $1.30 per 1,000 kWh, or 1.3 percent, for fuel cost recovery. This was the second increase associated with a three-year settlement approved by the NCUC in 2006. The settlement provided for an increase of $177 million effective October 1, 2006; $48 million effective October 1, 2007, as discussed above; and an additional increase of approximately $30 million in October 2008. On November 21, 2006, CUCA filed an appeal with the North Carolina Tenth District Court of Appeals of the NCUC's order approving the settlement on the grounds that the NCUC did not have the statutory authority to establish fuel rates for more than one year. On October 24, 2007, CUCA filed a motion to withdraw their appeal. On November 7, 2007, the North Carolina Tenth District Court of Appeals granted CUCA's motion. At December 31, 2007, PEC's North Carolina deferred fuel balance was $241 million, of which $114 million is expected to be collected after 2008 and has been classified as a long-term regulatory asset.

STORM COST RECOVERY

In February 2004, PEC filed with the SCPSC seeking permission to defer expenses incurred from the first quarter 2004 winter storm. In September 2004, the SCPSC approved PEC's request to defer the costs and amortize them ratably over five years beginning in January 2005. Approximately $9 million related to storm costs was deferred in 2004. For the years ended December 31, 2007, 2006 and 2005, PEC recognized $2 million of South Carolina storm amortization.

In October 2003, PEC filed with the NCUC seeking permission to defer approximately $24 million of expenses incurred from Hurricane Isabel and the February 2003 winter storms. In December 2003, the NCUC approved PEC's request to defer the costs associated with Hurricane Isabel and the February 2003 winter storms and amortize them over a period of five years. For the years ended December 31, 2007, 2006 and 2005, PEC recognized $5 million of North Carolina storm amortization.

OTHER MATTERS

PEC filed petitions on September 14, 2006, and September 22, 2006, with the SCPSC and NCUC, respectively, seeking authorization to defer and amortize the respective jurisdictional portion of $18 million of previously recorded operation and maintenance (O&M) expense relating to certain environmental remediation sites (See Note 21A). On October 11, 2006, the SCPSC granted PEC's petition to defer its jurisdictional amount, totaling $3 million, and amortize it over a five-year period beginning January 1, 2007. On October 19, 2006, the NCUC granted PEC's petition to defer its jurisdictional amount, totaling $15 million, and amortize it over a five-year period. However, the NCUC order directed that amortization begin in 2006, with an amortization expense of $3 million. As a result, during the fourth quarter of 2006, PEC reversed $18 million of O&M expense, established a regulatory asset and recorded $3 million of amortization expense. During the year ended December 31, 2007, PEC recorded $3 million of amortization expense. Additionally, PEC reduced the regulatory asset by $2 million during the year ended December 31, 2007, based on newly available data regarding certain remediation sites and insurance proceeds (See Note 21A).

The NCUC and SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The aggregate minimum and maximum amounts of cost recovery are $530 million and $750 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 $37 million in 2007. No additional depreciation expense from accelerated cost recovery was recorded in 2006 or 2005. Through December 31, 2007, PEC recorded total accelerated depreciation of $440 million, of which $363 million was recorded for the North Carolina jurisdiction and $77 million was recorded for the South Carolina jurisdiction.

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. Among other provisions, the law allows the utility to recover the costs of new demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs that are 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 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 and interruptible load. PEC has begun implementing a series of DSM and energy-efficiency programs and deferred $2 million of implementation and program costs through December 31, 2007, for future recovery.

PEC filed a petition on November 30, 2007, with the SCPSC seeking authorization to create a deferred account for DSM and energy-efficiency expenses. On December 21, 2007, the SCPSC issued an order granting PEC's petition. As a result, PEC has deferred an immaterial amount of implementation and program costs through December 31, 2007, for future recovery in the South Carolina jurisdiction. PEC anticipates applying for a DSM and energy- efficiency clause to recover the costs of these programs in 2008. We cannot predict the outcome of this matter.

C. PEF RETAIL RATE MATTERS

BASE RATE AGREEMENT

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009, with PEF having sole option to extend the agreement through the last billing cycle of June 2010 pursuant to the agreement. In accordance with the base rate agreement and as modified by a stipulation and settlement agreement approved by the FPSC on October 23, 2007, base rates were adjusted in January 2008 due to specified generation facilities placed in service in 2007. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006 whereby PEF will refund two-thirds of retail base revenues between the specified threshold and specified cap and 100 percent of revenues above the specified cap. However, PEF's retail base revenues did not exceed the specified 2007 threshold of $1.537 billion and thus no revenues were subject to revenue sharing. Both the 2007 base threshold of $1.537 billion and the 2007 cap of $1.588 billion will be adjusted annually for rolling average 10-year retail kWh sales growth. PEF's 2006 retail base rates did not exceed the threshold and no revenues were subject to the revenue sharing provisions. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the recovery of post-9/11 security costs through the capacity clause and the carrying costs of coal inventory in transit and coal procurement costs through the fuel clause. Under the settlement agreement, PEF is authorized to include an adjustment to increase common equity for the impact of Standard & Poor's Rating Services' (S&P's) imputed off-balance sheet debt for future capacity payments to qualifying facilities (QFs) and other entities under long-term purchase power agreements. This adjusted capital structure will be used for surveillance reporting with the FPSC and pass-through clause return calculations. PEF will use an authorized 11.75 percent ROE for cost-recovery clauses and AFUDC. In addition, PEF's adjusted equity ratio will be capped at 57.83 percent as calculated on a financial capital structure that includes the adjustment for the S&P imputed off-balance sheet debt. If PEF's regulatory ROE falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

PASS-THROUGH CLAUSE COST RECOVERY

On September 4, 2007, PEF filed a request with the FPSC seeking approval of a cost adjustment to reflect a projected over-collection of fuel costs in 2007, declining projected fuel costs for 2008 and other recovery clause factors. PEF asked the FPSC to approve a $163 million, or 4.53 percent, decrease in rates effective January 1, 2008. This cost adjustment would decrease residential bills by $5.00 for the first 1,000 kWh. As discussed above, residential base rates increased due to specified generation facilities placed in service in 2007 by $2.73 for the first 1,000 kWh effective January 1, 2008. After considering the net effect of the base rate increase and the proposed fuel cost adjustment, 2008 residential bills would decrease by a net amount of $2.27 for the first 1,000 kWh. The FPSC approved the cost-recovery rates for 2008 in an order dated January 8, 2008. At December 31, 2007, PEF's current regulatory liabilities totaled $173 million, which were comprised of over-recovered fuel and capacity costs of $140 million, accrued disallowed fuel costs of $14 million, over-recovered conservation costs of $14 million and over-recovered environmental compliance of $5 million.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and SO_2 allowance costs during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. The OPC claimed that although Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) were designed to burn a blend of coals, PEF failed to act to lower ratepayers' costs by purchasing the most economical blends of coal. 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 July 31, 2007, the FPSC heard this matter. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the 4-1 majority 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 included within PEF's deferred fuel cost at December 31, 2007. On October 25, 2007, the OPC requested the FPSC to reconsider its October 10, 2007 order asserting that the FPSC erred in not ordering a larger refund. PEF filed its opposition to the OPC's request on November 1, 2007. On February 12, 2008, the FPSC denied the OPC's request for reconsideration. PEF is also evaluating its options, including an appeal to the Florida Supreme Court of the FPSC's October 10, 2007 order. We cannot predict the outcome of this matter. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. On October 4, 2007, PEF filed a motion to establish a separate docket on the prudence of its coal purchases for CR4 and CR5 for the years 2006 and 2007. On October 17, 2007, the FPSC granted that motion. The OPC filed testimony in support of its position to require PEF to refund at least $14 million for alleged excessive fuel recovery charges for 2006 coal purchases. PEF believes its coal procurement practices have been prudent. We cannot predict the outcome of this matter.

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate CR3, bid rule exemption and recovery of the revenue requirements of the uprate through PEF's fuel recovery clause. To the extent the expenditures are prudently incurred, PEF's investment in the CR3 uprate is eligible for recovery through base rates. PEF's petition would allow for more prompt recovery. The multi-stage uprate will increase CR3's gross output by approximately 180 MW by 2012. PEF received NRC approval for a license amendment and implemented the first stage's design modification on January 31, 2008, and will apply for the required license amendment for the third stage's design modification. The petition filed with the FPSC included estimated project costs of approximately $382 million. These cost estimates may continue to change depending upon the results of more detailed engineering and development work and increased material, labor and equipment costs. On February 8, 2007, the FPSC issued an order approving the need certification petition and bid rule exemption. The request for recovery through PEF's fuel recovery clause was transferred to a separate docket filed on January 16, 2007. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. On March 27, 2007, the FPSC denied the motion to abate and directed the staff of the FPSC to conduct a hearing to determine whether the revenue requirements of the uprate should be recovered through the fuel recovery clause. On May 4, 2007, PEF filed amended testimony clarifying the scope of the project. The FPSC held a hearing on this matter on August 7 and 8, 2007. The staff of the FPSC recommended that PEF be allowed to recover prudent and reasonable costs of Phase 1, estimated at $6 million, through the fuel clause. The staff of the FPSC recommended that the costs of all other phases, estimated at $376 million, be considered in a base rate proceeding. On October 19, 2007, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. On November 21, 2007, PEF filed a petition with the FPSC seeking cost recovery under Florida's comprehensive energy bill enacted in 2006, and the FPSC's new nuclear cost-recovery rule. On February 13, 2008, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. PEF will proceed with cost recovery under Florida's comprehensive energy bill and the FPSC's nuclear cost-recovery rule based on the regulatory precedence established by a FPSC order to an unaffiliated Florida utility for a nuclear uprate project. We cannot predict the outcome of this matter.

STORM COST RECOVERY

On July 14, 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 the four hurricanes in 2004. The ruling allowed PEF to include a charge of approximately $3.27 on the average residential monthly customer bill of 1,000 kWh beginning August 1, 2005. The ruling by the FPSC approved the majority of PEF's requests with two exceptions: the reclassification of $8 million of previously deferred costs to utility plant and the reclassification of $17 million of previously deferred costs as O&M

expense, which was expensed in the second quarter of 2005. The amount included in the original November 2004 petition requesting recovery of $252 million was an estimate. On September 12, 2005, PEF filed a true-up to the original amount comprised primarily of an additional $19 million of costs partially offset by $6 million of adjustments resulting from allocating a higher portion of the costs to the wholesale jurisdiction and refining the FPSC adjustments. On November 9, 2005, the recovery of this difference was administratively approved by the FPSC, subject to audit by the FPSC staff. The net impact was included in customer bills beginning January 1, 2006. In 2007, 2006 and 2005, PEF recorded amortization of $75 million, $122 million and $50 million, respectively, associated with the recovery of these storm costs. The retail portion of storm restoration costs were fully recovered at December 31, 2007.

On April 25, 2006, PEF entered into a settlement agreement with 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 to replenish its storm reserve. The requested extension, which began August 2007, is expected to replenish the existing storm reserve by an estimated $126 million. During the third quarter of 2006, PEF and the intervenors modified the settlement agreement such 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. On August 29, 2006, the FPSC approved the settlement agreement as modified. Through December 31, 2007, PEF had recorded an additional $55 million of storm reserve from the extension of the storm surcharge. At December 31, 2007, PEF's storm reserve totaled $63 million.

FRANCHISE MATTERS

On June 1, 2005, Winter Park acquired PEF's electric distribution system that serves Winter Park for approximately $42 million. On June 1, 2005, PEF transferred the distribution system to Winter Park and recognized a pre-tax gain of approximately $25 million on the transaction, which is included as an offset to other utility expense on the Statements of Income. This amount was decreased $1 million in the third quarter of 2005 upon accumulation of the final capital expenditures incurred since arbitration. PEF also recorded a regulatory liability of $8 million for stranded cost revenues, which will be amortized to revenues over six years in accordance with the provisions of the transfer agreement with Winter Park. In June 2004, Winter Park executed a wholesale power supply contract with PEF with a five-year term and a renewal option.

OTHER MATTERS

On October 29, 2007, PEF 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 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 rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. Settlement discussions were held with major customers prior to the filing and a settlement agreement was reached on all issues. The settlement proposed a formula rate with a rate of return on equity of 10.8 percent. PEF received FERC approval of the settlement agreement on December 17, 2007. The new rates were effective January 1, 2008, and PEF estimates the impact of the new rates will increase 2008 revenues by $1 million to $2 million.

D. REGIONAL TRANSMISSION ORGANIZATIONS

In 2000, the FERC issued Order 2000, which set minimum characteristics and functions that regional transmission organizations (RTOs) must meet, including independent transmission service. In October 2000, as a result of Order 2000, PEC, along with Duke Energy Corporation and South Carolina Electric & Gas Company, filed an application with the FERC for approval of an RTO, GridSouth Transco, LLC (GridSouth). In July 2001, the FERC issued an order provisionally approving GridSouth. However, in July 2001, the FERC issued orders recommending that companies in the southeastern United States engage in mediation to develop a plan for a single RTO. PEC participated in the mediation; no consensus was reached on creating a southeast RTO. On August 11, 2005, the GridSouth participants notified the FERC that they had terminated the GridSouth project. By order issued October 20, 2005, the FERC terminated the GridSouth proceeding.

On November 16, 2007, PEC petitioned the NCUC to allow it to establish a regulatory asset for PEC's development costs of GridSouth pending disposition in a general rate proceeding. On January 14, 2008, the NCUC issued an order requesting interested parties to file comments regarding PEC's petition on or before January 28, 2008. On February 11, 2008, PEC filed response comments. On December 20, 2007, the NCUC issued an order for one of the other GridSouth partners. As part of that order, the NCUC ruled that the utility's GridSouth development costs should be amortized and recovered over a 10-year period beginning June 2002. Until the NCUC rules upon PEC's petition, PEC will apply the same accounting treatment to its GridSouth development costs. Consequently, in December 2007, PEC recorded an $11 million charge to amortization expense to reduce the North Carolina portion of development costs, which is included in depreciation and amortization on the Consolidated Statements of Income. PEC's recorded investment in GridSouth totaled $22 million and $33 million at December 31, 2007 and 2006. PEC expects to recover its GridSouth development costs based on precedent regulatory proceedings; in 2007, PEC reclassified its investment in GridSouth from other assets and deferred debits to regulatory assets on the Consolidated Balance Sheets. We cannot predict the outcome of this matter.

PEF was one of three major investor-owned Florida utilities that formed the GridFlorida RTO in 2000. A cost-benefit study conducted during 2005 concluded that the GridFlorida RTO was not cost effective for FPSC jurisdictional customers and shifted benefits to nonjurisdictional customers. In light of these findings, during 2006 the FPSC and the FERC closed their respective docketed proceedings and GridFlorida was dissolved. PEF fully recovered its development costs in GridFlorida from retail ratepayers through base rates.

E. NUCLEAR LICENSE RENEWALS

The NRC operating license for Robinson expires in 2030 and the licenses for Brunswick expire in 2036 for Unit No. 1 and 2034 for Unit No. 2. On November 14, 2006, PEC filed an application for a 20-year extension from the NRC on the operating license for Harris, which would extend the operating license through 2046, if approved. PEC anticipates a decision from the NRC in 2008. The NRC operating license held by PEF for CR3 currently expires in December 2016. PEF expects to submit an application requesting a 20-year extension of this license in the first quarter of 2009.

8. GOODWILL AND INTANGIBLE ASSETS

We perform annual goodwill impairment tests in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Goodwill was tested for impairment for both the PEC and PEF segments in the second quarters of 2007 and 2006; each test indicated no impairment.

Under SFAS No. 142, all goodwill is assigned to our reporting units that are expected to benefit from the synergies of the business combination. At December 31, 2007 and 2006, 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. There were no changes to the assignment of the carrying amounts to PEC and PEF in 2007 or 2006.

Goodwill impairment tests were performed at our CCO-Georgia Operations reporting unit level, which was comprised of four nonregulated generating plants (Georgia Operations). As a result of our evaluation of certain business opportunities that impacted the future cash flows of our Georgia Operations, we performed the annual goodwill impairment test during the first quarter of 2006. We estimated the fair value of that reporting unit using the expected present value of future cash flows. As a result of that test, we recognized a pre-tax goodwill impairment charge of $64 million ($39 million after-tax) during the first quarter of 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income (See Note 3A).

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding future synthetic fuels production. With the idling of these facilities, we performed an evaluation of the intangible assets, which were comprised primarily of capitalized acquisition costs (See Note 9 for impairment of related long-lived assets). The impairment test considered numerous factors including, among other things, continued high oil prices and the then-current idled state of our synthetic fuels facilities. We estimated the fair value using the expected present value of future cash flows. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $27 million ($17 million after-tax) during the quarter ended June 30, 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. This charge represented the entirety of the synthetic fuels intangible assets; these assets had been reported within our former Coal and Synthetic Fuels segment (See Note 3B).

9. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. In 2006, we recorded pre-tax long-lived asset and investment impairments and other charges of $65 million, of which $64 million has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. PEC recorded pre-tax long-lived asset and investment impairments and other charges of $1 million in both 2006 and 2005.

A. LONG-LIVED ASSETS

Due to rising current and future oil prices, in the third and fourth quarters of 2005 we tested our synthetic fuels plant assets for impairment. These tests indicated that the assets were recoverable and no impairment charge was recorded. See Note 22D for additional information.

Concurrent with the synthetic fuels intangibles impairment evaluation discussed in Note 8, we also performed an impairment evaluation of related long-lived assets during the second quarter of 2006. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $64 million ($38 million after-tax) during the quarter ended June 30, 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income, as discussed in Note 3B. This charge represents the entirety of the asset carrying value of our synthetic fuels manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities are located. These assets had been reported within our former Coal and Synthetic Fuels segment. There were no impairments of long-lived assets in 2007.

B. INVESTMENTS

We evaluate declines in value of investments under the criteria of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), and FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairments and Its Application to Certain Investments" (See Note 1D). 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 and other available-for-sale securities. See Note 13 for additional information.

We continually review PEC's affordable housing investment (AHI) portfolio for impairment. There were no other-than-temporary impairments in 2007. As a result of various factors, including continued operating losses of the AHI portfolio and management issues arising at certain properties within the AHI portfolio, we recorded impairment charges of $1 million on a pre-tax basis in both 2006 and 2005.

10. EQUITY

A. COMMON STOCK

PROGRESS ENERGY

At December 31, 2007 and 2006, we had 500 million shares of common stock authorized under our charter, of which 260 million shares and 256 million shares, respectively, were outstanding. During 2007, 2006 and 2005, respectively, we issued approximately 3.4 million, 4.2 million and 4.8 million shares of common stock, resulting in approximately $151 million, $185 million and $208 million in proceeds. Included in these amounts for 2007, 2006 and 2005, respectively, were approximately 1.0 million, 1.6 million and 4.6 million shares for proceeds of approximately $46 million, $70 million and $199 million, to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan.

At December 31, 2007 and 2006, we had approximately 50 million shares and 54 million shares, respectively, of common stock authorized by the board of directors that remained unissued and reserved, primarily to satisfy the requirements of our stock plans. In 2002, the board of directors authorized meeting the requirements of the 401(k) and the Investor Plus Stock Purchase Plan with original issue shares. We continue to meet the requirements of the restricted stock plan with issued and outstanding shares.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2007, there were no significant restrictions on the use of retained earnings (See Note 12).

PEC

At December 31, 2007 and 2006, 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, 2007, there were no significant restrictions on the use of retained earnings. See Note 12 for additional dividend restrictions related to PEC.

PEF

At December 31, 2007 and 2006, 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, 2007, there were no significant restrictions on the use of retained earnings. See Note 12 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, 2007 and 2006, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has matching and incentive goal features, 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 1.7 million and 2.3 million ESOP suspense shares at December 31, 2007 and 2006, respectively, with a fair value of $82 million and $112 million, respectively. ESOP shares allocated to plan participants totaled 10.6 million and 10.9 million at December 31, 2007 and 2006, respectively. Our matching and incentive goal compensation cost under the 401(k) is determined based on matching percentages and incentive goal attainment 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 incentive goal compensation are accrued during the fiscal year and typically paid in shares in the following year, while costs for the matching component are typically met with shares in the same year incurred. Matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $23 million, $14 million and $18 million for the years ended December 31, 2007, 2006 and 2005, respectively. Total matching and incentive costs were approximately $30 million, $23 million and $30 million for the years ended December 31, 2007, 2006 and 2005, 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.

Effective January 1, 2008, the 401(k) Plan was revised. As revised, the employer match percentage was increased and the employee stock incentive plan based on goal attainment was discontinued.

PEC

PEC's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $14 million, $8 million and $11 million for the years ended December 31, 2007, 2006 and 2005, respectively. Total matching and incentive costs were approximately $18 million, $13 million and $17 million for the years ended December 31, 2007, 2006 and 2005, respectively.

PEF

PEF's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $4 million, $2 million and $4 million for the years ended December 31, 2007, 2006 and 2005, respectively. Total matching and incentive costs were approximately $6 million, $4 million and $6 million for the years ended December 31, 2007, 2006 and 2005, 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 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, 2007, 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	4.0	$43.70
Canceled	–	45.55
Exercised	(2.3)	43.47
Options outstanding, December 31	1.7	43.99
Options exercisable, December 31	1.7	43.99

The options outstanding and exercisable at December 31, 2007, had a weighted-average remaining contractual life of 5.0 years and an aggregate intrinsic value of $8 million. Total intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005, respectively, was $17 million, $10 million and less than $1 million.

Compensation cost, for pro forma purposes prior to the adoption of SFAS No. 123R and for expense purposes subsequent to the adoption, is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The fair value for these options was estimated at the grant date using a Black-Scholes option pricing model. Dividend yield and the volatility factor were calculated using three years of historical trend information. The expected term was based on the contractual life of the options.

As of December 31, 2006, all options were fully vested; therefore, no compensation expense was recognized in 2007. Stock option expense totaling $2 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year. Stock option expense totaling $3 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year.

As previously indicated, we did not record stock option expense prior to the adoption of SFAS No. 123R as of July 1, 2005. The following table illustrates the effect on our net income and earnings per share if the fair value method had been applied to all outstanding and nonvested awards in each period:

(in millions, except per share data)	2005
Net income, as reported	$697
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	2
Pro forma net income	$695
Earnings per share	
Basic – as reported	$2.82
Basic – pro forma	2.81
Diluted – as reported	2.82
Diluted – pro forma	2.81

Cash received from the exercise of stock options totaled $105 million, $115 million and $8 million, respectively, during the years ended December 31, 2007, 2006 and 2005. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2007 and 2006, was $6 million and $4 million, respectively. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2005, was not significant.

PEC

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. As of December 31, 2006, all options were fully vested; therefore no compensation expense was recognized in 2007.

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year.

As previously indicated, we did not record stock option expense prior to the adoption of SFAS No. 123R as of July 1, 2005. The following table illustrates the effect on our net income if the fair value method had been applied to all outstanding and nonvested awards in each period:

(in millions)	2005
Net income, as reported	$493
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	2
Pro forma net income	$491

PEF

Stock option expense totaling less than $1 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. As of December 31, 2006, all options were fully vested; therefore no compensation expense was recognized in 2007.

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year.

As previously indicated, we did not record stock option expense prior to the adoption of SFAS No. 123R as of July 1, 2005. The following table illustrates the effect on our net income if the fair value method had been applied to all outstanding and nonvested awards in each period:

(in millions)	2005
Net income, as reported	$260
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	1
Pro forma net income	$259

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 of which were 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. 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. 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 totaling $3 million, $4 million and $5 million were paid in the years ended December 31, 2007, 2006 and 2005, respectively. A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2007, and changes during the year then ended is presented below:

	Number of Stock-Settled Performance Shares(a)	Weighted-Average
Beginning balance	1,044,583	$44.26
Granted	892,410	50.70
Paid(b)	(190,567)	50.70
Forfeited	(116,431)	44.84
Ending balance	1,629,995	$44.97

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.

Shares paid include only target shares as originally granted. Additional shares of 106,478 were issued and paid due to exceeding established performance thresholds and due to dividends earned.

For the years ended December 31, 2006 and 2005, the weighted-average grant date fair value of stock-settled performance shares granted was $44.27 and $44.24, respectively.

The Restricted Stock Award (RSA) 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 not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. A summary of the status of the nonvested restricted stock shares at December 31, 2007, and changes during the year then ended, is presented below:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	604,238	$43.82
Granted	7,000	49.54
Vested	(303,935)	44.08
Forfeited	(38,668)	43.16
Ending balance	268,635	$43.77

For the years ended December 31, 2006 and 2005, the weighted-average grant date fair value of restricted stock granted was $44.51 and $42.56, respectively.

The total fair value of restricted stock awards vested during the years ended December 31, 2007, 2006 and 2005 was $13 million, $4 million and $7 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million during the years ended December 31, 2006 and 2005, respectively. Cash expended to purchase shares for 2007 was not significant due to the curtailment of the RSA program and the rollout of the new restricted stock unit (RSU) program.

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. 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. RSUs are not included as shares outstanding in the basic earnings per share calculation until shares are no longer forfeitable. Units are converted to shares upon vesting. A summary of the status of nonvested RSUs at December 31, 2007, and changes during the year then ended, is presented below:

	Number of Restricted Units	Weighted-Average Grant Date Fair Value
Beginning balance	-	$-
Granted	913,282	50.33
Vested	(49,430)	50.70
Forfeited	(39,394)	50.70
Ending balance	824,458	$50.29

The total fair value of RSUs vested during the year ended December 31, 2007, was $3 million. There were no expenditures to purchase stock to satisfy RSU plan obligations in 2007.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $70 million for the year ended December 31, 2007, with a recognized tax benefit of $27 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $25 million with a recognized tax benefit of $10 million and $10 million, with a recognized tax benefit of $4 million, for the years ended December 31, 2006 and 2005, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2007, there was $51 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 1.8 years.

PEC

PEC's Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $41 million for the year ended December 31, 2007, with a recognized tax benefit of $16 million. The total expense recognized on PEC's Consolidated Statements of Income for other stock-based compensation plans was $14 million with a recognized tax benefit of $6 million and $7 million, with a recognized tax benefit of $3 million, for the years ended December 31, 2006 and 2005, 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 $22 million for the year ended December 31, 2007, with a recognized tax benefit of $9 million. The total expense recognized on PEF's Statements of Income for other stock-based compensation plans was $7 million for the year ended December 31, 2006, with a recognized tax benefit of $3 million. The total expense recognized on PEF's Statements of Income for other stock-based compensation plans was $3 million for the year ended December 31, 2005, with a recognized tax benefit of $1 million. 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. Diluted earnings per share include the effects of the nonvested portion of restricted stock, restricted stock unit awards and 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)	**2007**	2006	2005
Weighted-average common shares – basic	**256.1**	250.4	246.6
Net effect of dilutive stock-based compensation plans	**0.6**	0.4	0.4
Weighted-average shares – fully diluted	**256.7**	250.8	247.0

There were no adjustments to net income or to income from continuing operations 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 shares totaled 1.8 million, 2.4 million and 3.0 million for the years ended December 31, 2007, 2006 and 2005, respectively. There were 0.1 million, 1.8 million and 2.9 million stock options outstanding at December 31, 2007, 2006 and 2005, 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

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

	Progress Energy		PEC		PEF	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Loss on cash flow hedges	**$(23)**	$(14)	**$(10)**	$(5)	**$(8)**	$(1)
Pension and other postretirement benefits	**(13)**	(39)	**–**	–	**–**	–
Other	**2**	4	**–**	4	**–**	–
Total accumulated other comprehensive loss	**$(34)**	$(49)	**$(10)**	$(1)	**$(8)**	$(1)

11. PREFERRED STOCK OF SUBSIDIARIES – NOT SUBJECT TO MANDATORY REDEMPTION

All of our preferred stock was issued by our subsidiaries and was not subject to mandatory redemption. At December 31, 2007 and 2006, 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

12. 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, 2007):

(in millions)		2007	2006
Progress Energy, Inc.			
Senior unsecured notes, maturing 2010-2031	6.98%	**$2,600**	$2,600
Unamortized fair value hedge gain, net		**–**	(1)
Unamortized premium and discount, net		**(3)**	(18)
Long-term debt, net		**2,597**	2,581
PEC			
First mortgage bonds, maturing 2009-2035	5.65%	**2,000**	2,200
Pollution control obligations, maturing 2017-2024	4.57%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Medium-term notes, maturing 2008	6.65%	**300**	300
Miscellaneous notes		**22**	22
Unamortized premium and discount, net		**(8)**	(21)
Current portion of long-term debt		**(300)**	(200)
Long-term debt, net		**3,183**	3,470
PEF			
First mortgage bonds, maturing 2008-2037	5.64%	**2,380**	1,630
Pollution control obligations, maturing 2018-2027	4.32%	**241**	241
Senior unsecured notes, maturing 2008	5.27%	**450**	450
Medium-term notes, maturing 2008-2028	6.75%	**152**	241
Unamortized premium and discount, net		**(5)**	(5)
Current portion of long-term debt		**(532)**	(89)
Long-term debt, net		**2,686**	2,468
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(38)**	(38)
Long-term debt, net		**271**	271
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2008	6.46%	**45**	80
Current portion of long-term debt		**(45)**	(35)
Long-term debt, net		**–**	45
Progress Energy consolidated long-term debt, net		**$8,737**	$8,835

On September 18, 2007, PEF issued $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. The proceeds were used to repay PEF's utility money pool borrowings and the remainder was placed in temporary investments for general corporate use as needed.

At December 31, 2007 and 2006, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2007 and 2006, we had no outstanding borrowings under our credit facilities. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following table summarizes our revolving credit agreements (RCAs) and available capacity at December 31, 2007:

(in millions)	Description	Total	Outstanding	Reserved[(a)]	Available
Progress Energy, Inc.	Five-year (expiring 5/3/11)	$1,130	$ –	$220	$910
PEC	Five-year (expiring 6/28/10)	450	–	–	450
PEF	Five-year (expiring 3/28/10)	450	–	–	450
Total credit facilities		$2,030	$ –	$220	$1,810

(a) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2007, Progress Energy, Inc. had a total amount of $19 million of letters of credit issued, which were supported by the RCA.

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 by Moody's Investors Service, Inc. (Moody's) and BBB by 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 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 by Moody's and BBB by S&P.

The following table summarizes our outstanding commercial paper and other short-term debt and related weighted-average interest rates at December 31, 2007:

(in millions)		
Progress Energy, Inc.	5.48%	$201
PEC		–
PEF		–
Total	5.48%	$201

We had no commercial paper outstanding or other short-term debt at December 31, 2006.

The following table presents the aggregate maturities of long-term debt at December 31, 2007:

(in millions)	Progress Energy Consolidated	PEC	PEF
2008	$877	$300	$532
2009	400	400	–
2010	406	6	300
2011	1,000	–	300
2012	950	500	–
Thereafter	6,035	2,285	2,091
Total	$9,668	$3,491	$3,223

B. COVENANTS AND DEFAULT PROVISIONS

FINANCIAL COVENANTS

Progress Energy, Inc.'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, 2007, the maximum and calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, were as follows:

1

2Company	Maximum Ratio	Actual Ratio (a)
Progress Energy, Inc.	68%	54.4%
PEC	65%	48.8%
PEF	65%	53.2%

(a) Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees that are 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 Progress Energy, Inc. 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. Progress Energy, Inc.'s cross-default provision can be triggered by Progress Energy, Inc. and its significant subsidiaries, as defined in the credit agreement, (i.e., PEC, Florida Progress, PEF, Progress Capital Holdings, Inc. and PVI). PEC's and PEF's cross-default provisions can only be triggered 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 Progress Energy, Inc.'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 Progress Energy, Inc., 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 $2.6 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 Progress Energy, Inc.'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, 2007, Progress Energy, Inc. had no shares of preferred stock outstanding.

Certain documents restrict the payment of dividends by Progress Energy, Inc.'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, 2007, 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 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, 2007, PEC's common stock equity was approximately 53.8 percent of total capitalization. At December 31, 2007, 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, 2007, 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 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, 2007, PEF's common stock equity was approximately 52.5 percent of total capitalization. At December 31, 2007, 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, 2007, PEC and PEF had a total of $2.669 billion and $2.621 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.

13. INVESTMENTS AND FAIR VALUE OF FINANCIAL INSTRUMENTS

A. INVESTMENTS

At December 31, 2007 and 2006, 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)	**2007**	2006	**2007**	2006	**2007**	2006
Nuclear decommissioning trust (See Note 5D)	**$1,384**	$1,287	**$804**	$735	**$580**	$552
Investments in equity securities (a)	**–**	5	**–**	4	**–**	–
Equity method investments (b)	**23**	24	**11**	13	**2**	1
Cost investments (c)	**8**	8	**3**	2	**–**	–
Benefit investment trusts (d)	**82**	80	**2**	2	**–**	–
Company-owned life insurance (d)	**168**	161	**112**	99	**39**	39
Marketable debt securities (e)	**1**	71	**1**	50	**–**	–
Total	**$1,666**	$1,636	**$933**	$905	**$621**	$592

(a) Certain investments in equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115 (See Note 1). These investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

Investments in unconsolidated companies are included in miscellaneous other property and investments in the Consolidated Balance Sheets using the equity method of accounting (See Note 1). These investments are primarily in limited liability corporations and limited partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 20).

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

Investments in company-owned life insurance and other benefit plan assets are included in miscellaneous other property and investments in the Consolidated Balance Sheets and approximate fair value due to the short maturity of the instruments.

We actively invest available cash balances in various financial instruments, such as tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through arrangements with banks that provide daily and weekly liquidity and 7-, 28- and 35-day auctions that allow for the redemption of the investment at its face amount plus earned income. As we intend to sell these instruments within one year or less, generally within 30 days, from the balance sheet date, they are classified as short-term investments.

B. FAIR VALUE OF FINANCIAL INSTRUMENTS

PROGRESS ENERGY

DEBT

The carrying amount of our long-term debt, including current maturities, was $9.614 billion and $9.159 billion at December 31, 2007 and 2006, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $9.897 billion and $9.543 billion at December 31, 2007 and 2006, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115. These investments include investments held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning nuclear plants (See Note 5D). These nuclear decommissioning trust funds are primarily invested in stocks, bonds and cash equivalents that are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust funds, we hold other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the Consolidated Balance Sheets at amounts that approximate fair value. Our available-for-sale securities at December 31, 2007 and 2006 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2007

(in millions)	**Book Value**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$465**	**$354**	**$819**
Debt securities	**574**	**11**	**585**
Cash equivalents	**18**	**–**	**18**
Total	**$1,057**	**$365**	**$1,422**

2006

(in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$428	$324	$752
Debt securities	606	13	619
Cash equivalents	19	–	19
Total	$1,053	$337	$1,390

At December 31, 2007, 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	145
Due after five through 10 years	198
Due after 10 years	234
Total	$585

Selected information about our sales of available-for-sale securities during the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

(in millions)	2007	2006	2005
Proceeds	**$1,334**	$2,547	$3,755
Realized gains	**35**	33	26
Realized losses	**37**	24	31

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Therefore, we consider available-for-sale securities in our nuclear decommissioning trust funds to be impaired if they are in a loss position. These impairments along with unrealized gains are included in our regulatory liabilities (See Note 7A) and have no earnings impact. Some of our benefit investment trusts are also managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2007 and 2006 for investments in these 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, 2007 and 2006 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 $3.483 billion and $3.670 billion at December 31, 2007 and 2006, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.545 billion and $3.732 billion at December 31, 2007 and 2006, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 5D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents and are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the PEC Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust fund, PEC holds other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the PEC Consolidated Balance Sheets at amounts that approximate fair value. PEC's available-for-sale securities at December 31, 2007 and 2006 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2007

(in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	**$256**	**$191**	**$447**
Debt securities	**341**	**6**	**347**
Cash equivalents	**11**	**–**	**11**
Total	**$608**	**$197**	**$805**

2006

(in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$232	$170	$402
Debt securities	364	7	371
Cash equivalents	9	–	9
Total	$605	$177	$782

At December 31, 2007, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$7
Due after one through five years	86
Due after five through 10 years	99
Due after 10 years	155
Total	$347

Selected information about PEC's sales of available-for-sale securities during the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

(in millions)	2007	2006	2005
Proceeds	**$609**	$995	$1,678
Realized gains	**12**	21	13
Realized losses	**22**	14	16

Available-for-sale securities in PEC's nuclear decommissioning trust funds are impaired if they are in a loss position as described above. 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, 2007 and 2006 PEC's other securities had no investments in a continuous loss position for greater than 12 months.

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $3.218 billion and $2.557 billion at December 31, 2007 and 2006, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.239 and $2.567 billion at December 31, 2007 and 2006, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 5D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents and are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. PEF's available-for-sale securities at December 31, 2007 and 2006 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2007 **(in millions)**	**Book Value**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$209**	**$163**	**$372**
Debt securities	**193**	**5**	**198**
Cash equivalents	**7**	**–**	**7**
Total	**$409**	**$168**	**$577**

2006 (in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$196	$154	$350
Debt securities	184	6	190
Cash equivalents	9	–	9
Total	$389	$160	$549

At December 31, 2007, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$1
Due after one through five years	51
Due after five through 10 years	84
Due after 10 years	62
Total	$198

Selected information about PEF's sales of available-for-sale securities for the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2007**	2006	2005
Proceeds	**$535**	$509	$330
Realized gains	**22**	12	13
Realized losses	**14**	9	13

Available-for-sale securities in PEF's nuclear decommissioning trust funds are impaired if they are in a loss position as described above. 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, 2007 and 2006 PEF's other securities had no investments in a loss position.

14. INCOME TAXES

We provide deferred income taxes for temporary differences. These occur when there are 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 under SFAS No. 109 is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. 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)	2007	2006
Deferred income tax assets		
Asset retirement obligation liability	**$146**	$141
Compensation accruals	**101**	86
Deferred revenue	**–**	28
Derivative instruments	**–**	42
Environmental remediation liability	**32**	36
Income taxes refundable through future rates	**317**	216
Investments	**–**	28
Pension and other postretirement benefits	**306**	364
Unbilled revenue	**41**	36
Other	**122**	103
Federal income tax credit carry forward	**836**	851
State net operating loss carry forward (net of federal expense)	**87**	54
Valuation allowance	**(79)**	(71)
Total deferred income tax assets	**1,909**	1,914
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,482)**	(1,379)
Deferred fuel recovery	**(64)**	(60)
Deferred storm costs	**(6)**	(51)
Derivative instruments	**(59)**	–
Income taxes recoverable through future rates	**(384)**	(436)
Investments	**(25)**	–
Prepaid pension costs	**(18)**	–
Other	**(50)**	(66)
Total deferred income tax liabilities	**(2,088)**	(1,992)
Total net deferred income tax liabilities	**$(179)**	$(78)

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

(in millions)	2007	2006
Current deferred income tax assets	$27	$142
Noncurrent deferred income tax assets, included in other assets and deferred debits	65	17
Current deferred income tax liabilities, included in other current liabilities	(5)	–
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	(266)	(237)
Total net deferred income tax liabilities	$(179)	$(78)

At December 31, 2007, the federal income tax credit carry forward includes $772 million of alternative minimum tax credits that do not expire and $64 million of general business credits that will expire during the period 2020 through 2027.

At December 31, 2007, we had gross state net operating loss carry forwards of $1.9 billion that will expire during the period 2008 through 2026.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We established additional valuation allowances of $8 million during 2007. 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:

	2007	2006	2005
Effective income tax rate	32.3%	37.5%	36.1%
State income taxes, net of federal benefit	(2.8)	(3.5)	(3.5)
Investment tax credit amortization	1.1	1.3	1.6
Employee stock ownership plan dividends	1.1	1.3	1.5
Domestic manufacturing deduction	1.0	0.4	1.0
Other differences, net	2.3	(2.0)	(1.7)
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)	2007	2006	2005
Current – federal	$285	$394	$441
– state	36	70	74
Deferred – federal	13	(94)	(173)
– state	11	(17)	(31)
State net operating loss carry forward	1	(2)	–
Investment tax credit	(12)	(12)	(13)
Total income tax expense	$334	$339	$298

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

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2007 or 2006.

- Taxes related to discontinued operations recorded net of tax for 2007, 2006 and 2005, which are presented separately in Notes 3A through 3H.

- Taxes related to other comprehensive income recorded net of tax for 2007, 2006 and 2005, 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. Current tax benefit of $3 million, which was recorded in common stock during 2006, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $2 million, which was recorded in common stock during 2005, 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.

In July 2006, the FASB issued FIN 48, which clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. A two-step process is required for the application of FIN 48; recognition of the tax benefit based on a "more-likely-than-not" threshold, and measurement of the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with the taxing authority. We adopted the provisions of FIN 48 on January 1, 2007, which was accounted for as a $2 million reduction of the January 1, 2007, balance of retained earnings and a $4 million increase in regulatory assets. Including the cumulative effect impact, our liability for unrecognized tax benefits at January 1, 2007, was $126 million. Of the total amount of unrecognized tax benefits at January 1, 2007, $24 million would have affected the effective tax rate for income from continuing operations, if recognized. At December 31, 2007, our liability for unrecognized tax benefits decreased to $93 million and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations decreased to $10 million. A reconciliation of the 2007 beginning and ending balances for unrecognized tax benefits is as follows:

(in millions)	
Unrecognized tax benefits at January 1, 2007	**$126**
Gross amounts of increases as a result of tax positions taken in a prior period	**32**
Gross amounts of decreases as a result of tax positions taken in a prior period	**(41)**
Gross amounts of increases as a result of tax positions taken in the current period	**22**
Gross amounts of decreases as a result of tax positions taken in the current period	**(32)**
Amounts of net decreases relating to settlements with taxing authorities	**(14)**
Reductions as a result of a lapse of the applicable statute of limitations	–
Unrecognized tax benefits at December 31, 2007	**$93**

At December 31, 2006 and 2005, we had recorded $76 million and $115 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Consolidated Balance Sheets.

Prior to the adoption of FIN 48, we and the Utilities accounted for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2006 and 2005, we had recorded $27 million and $60 million, respectively, of tax contingency reserves under SFAS No. 5, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

We and our subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state jurisdictions. During 2007, we closed federal tax years 1998 to 2003. Our open federal tax years are from 2004 forward and our open state tax years in our major jurisdictions are generally from 1992 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when those examinations will be completed. We are not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2008.

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 2007, the interest expense related to unrecognized tax benefits was $1 million, net, of which a $15 million expense component was deferred as a regulatory asset by PEF and not recognized in our Consolidated Statement of Operations. During 2007 there were no penalties related to unrecognized tax benefits. As of January 1, 2007, we had accrued $24 million for interest and penalties. As of December 31, 2007, we have accrued $23 million for interest and penalties, which are included in other liabilities and deferred credits on the Consolidated Balance Sheets.

PEC

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

(in millions)	**2007**	2006
Deferred income tax assets:		
Asset retirement obligation liability	**$140**	$132
Compensation accruals	**55**	47
Deferred revenue	**–**	28
Income taxes refundable through future rates	**82**	68
Pension and other postretirement benefits	**166**	200
Other	**40**	37
Federal income tax credit carry forward	**1**	1
Total deferred income tax assets	**484**	513
Deferred income tax liabilities:		
Accumulated depreciation and property cost differences	**(1,013)**	(930)
Deferred fuel recovery	**(60)**	(55)
Income taxes recoverable through future rates	**(291)**	(317)
Other	**(7)**	(37)
Total deferred income tax liabilities	**(1,371)**	(1,339)
Total net deferred income tax liabilities	**$(887)**	$(826)

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

(in millions)	**2007**	2006
Current deferred income tax assets, included in prepayments and other current assets	**$8**	$34
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(895)**	(860)
Total net deferred income tax liabilities	**$(887)**	$(826)

At December 31, 2007, the federal income tax credit carry forward includes $1 million of general business credits that will expire in 2020.

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

	2007	2006	2005
Effective income tax rate	**37.1%**	36.7%	32.7%
State income taxes, net of federal benefit	**(2.3)**	(2.3)	(2.1)
Investment tax credit amortization	**0.7**	0.8	1.1
Domestic manufacturing deduction	**1.1**	0.6	0.7
Progress Energy tax benefit allocation	**–**	–	2.9
Other differences, net	**(1.6)**	(0.8)	(0.3)
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)	**2007**	2006	2005
Current – federal	**$235**	$285	$343
– state	**19**	39	45
Deferred – federal	**34**	(42)	(120)
– state	**13**	(11)	(21)
Investment tax credit	**(6)**	(6)	(8)
Total income tax expense	**$295**	$265	$239

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

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2007 or 2006.

- Taxes related to other comprehensive income recorded net of tax for 2007, 2006 and 2005, 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. Current tax benefit of $1 million, which was recorded in common stock during 2006, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $1 million, which was recorded in common stock during 2005, 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.

PEC and each of its wholly owned subsidiaries have entered into the Tax Agreement with Progress Energy (See Note 1D). PEC's intercompany tax payable was approximately $27 million and $51 million at December 31, 2007 and 2006, respectively.

PEC adopted the provisions of FIN 48 on January 1, 2007, which was accounted for as a $6 million reduction of the January 1, 2007, balance of retained earnings. Including the cumulative effect impact, PEC's liability for unrecognized tax benefits at January 1, 2007, was $43 million. Of the total amount of unrecognized tax benefits at January 1, 2007, $9 million would have affected the effective tax rate, if recognized. At December 31, 2007, PEC's liability for unrecognized tax benefits decreased to $41 million, and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $9 million. A reconciliation of the 2007 beginning and ending balances for unrecognized tax benefits is as follows:

(in millions)	
Unrecognized tax benefits at January 1, 2007	$43
Gross amounts of increases as a result of tax positions taken in a prior period	3
Gross amounts of decreases as a result of tax positions taken in a prior period	(15)
Gross amounts of increases as a result of tax positions taken in the current period	22
Gross amounts of decreases as a result of tax positions taken in the current period	(5)
Amounts of decreases relating to settlements with taxing authorities	(7)
Reductions as a result of a lapse of the applicable statute of limitations	–
Unrecognized tax benefits at December 31, 2007	$41

At December 31, 2006 and 2005, PEC had recorded $49 million and $92 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Consolidated Balance Sheets.

At December 31, 2006 and 2005, PEC had recorded $5 million and $2 million, respectively, of tax contingency reserves under SFAS No. 5, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

We file consolidated federal and state income tax returns that include PEC. In addition, PEC files stand-alone tax returns in various state jurisdictions. During 2007, we closed federal tax years 1998 to 2003. PEC's open federal tax years are from 2004 forward and PEC's open state tax years in our major jurisdictions are generally from 1992 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. PEC cannot predict when those examinations will be completed. PEC is not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the twelve-month period ending December 31, 2008.

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 2007, the interest expense and penalties related to uncertain tax benefits was $4 million and $0 respectively. As of January 1, 2007, PEC had accrued $4 million for interest and penalties. At December 31, 2007, PEC had accrued $8 million for interest and penalties, which is included in other liabilities and deferred credits on the Consolidated Balance Sheets.

PEF

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

(in millions)	2007	2006
Deferred income tax assets		
Compensation accruals	**$21**	$15
Derivative instruments	**–**	30
Environmental remediation liability	**18**	24
Income taxes refundable through future rates	**184**	95
Pension and other postretirement benefits	**142**	150
Reserve for storm damage	**25**	2
Unbilled revenue	**41**	36
Other	**56**	53
Total deferred income tax assets	**487**	405
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(451)**	(429)
Deferred storm costs	**(6)**	(45)
Derivative instruments	**(64)**	–
Income taxes recoverable through future rates	**(93)**	(119)
Investments	**(63)**	(61)
Prepaid pension costs	**(86)**	(67)
Other	**(31)**	(38)
Total deferred income tax liabilities	**(794)**	(759)
Total net deferred income tax liabilities	**$(307)**	$(354)

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

(in millions)	2007	2006
Current deferred income tax assets	**$39**	$86
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(346)**	(440)
Total net deferred income tax liabilities	**$(307)**	$(354)

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

	2007	2006	2005
Effective income tax rate	**31.2%**	37.0%	31.8%
State income taxes, net of federal benefit	**(3.3)**	(3.6)	(3.3)
Investment tax credit amortization	**1.3**	1.2	1.4
Domestic manufacturing deduction	**0.8**	0.3	0.9
Progress Energy tax benefit allocation	**–**	–	3.2
AFUDC equity	**2.6**	0.7	0.7
Other differences, net	**2.4**	(0.6)	0.3
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)	**2007**	2006	2005
Current – federal	**$160**	$207	$146
– state	**28**	34	25
Deferred – federal	**(33)**	(36)	(39)
– state	**(5)**	(6)	(6)
Investment tax credit	**(6)**	(6)	(5)
Total income tax expense	**$144**	$193	$121

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

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2007 or 2006.
- Taxes related to other comprehensive income recorded net of tax for 2007, 2006 and 2005, 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, 2006 and 2005, 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.

PEF has entered into the Tax Agreement with Progress Energy (See Note 1D). PEF's intercompany tax receivable was approximately $41 million and $47 million at December 31, 2007 and 2006, respectively.

PEF adopted the provisions of FIN 48 on January 1, 2007, which was accounted for as a less than $1 million reduction of the January 1, 2007, balance of retained earnings and a $4 million increase in regulatory assets. Including the cumulative effect impact, PEF's liability for unrecognized tax benefits at January 1, 2007, was $72 million. Of the total amount of unrecognized tax benefits at January 1, 2007, $4 million would have affected the effective tax rate, if recognized. At December 31, 2007, PEF's liability for unrecognized tax benefits decreased to $55 million and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate decreased to $3 million. A reconciliation of the 2007 beginning and ending balances for unrecognized tax benefits is as follows:

(in millions)	
Unrecognized tax benefits at January 1, 2007	**$72**
Gross amounts of increases as a result of tax positions taken in a prior period	**23**
Gross amounts of decreases as a result of tax positions taken in a prior period	**(4)**
Gross amounts of increases as a result of tax positions taken in the current period	**2**
Gross amounts of decreases as a result of tax positions taken in the current period	**(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 December 31, 2007	**$55**

At December 31, 2006 and 2005, PEF had recorded $26 million and $17 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Balance Sheets.

At December 31, 2006 and 2005, respectively, PEF had recorded $5 million and $7 million of tax contingency reserves under SFAS No. 5, excluding accrued interest and penalties, which were included in other current liabilities on the Balance Sheets.

We file consolidated federal and state income tax returns that include PEF. During 2007, we closed federal tax years 1998 to 2003. PEF's open federal tax years are from 2004 forward and PEF's open state tax years are generally from 1998 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. PEF cannot predict when those examinations will be completed. PEF is not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the twelve-month period ending December 31, 2008.

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, with the amortization included in interest charges on the Statements of Income. Penalties are included in other, net on the Statements of Income. During 2007, the interest expense recorded as a regulatory asset was $15 million and penalties related to unrecognized tax benefits was $0. At January 1, 2007, PEF had accrued $7 million for interest and penalties. At December 31, 2007, PEF had accrued $18 million for interest and penalties, which is included in other liabilities and deferred credits on the Balance Sheets.

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million contingent value obligations (CVOs). Each CVO represents the right of the holder to receive contingent payments based on the performance of four Earthco synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. 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, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively.

During 2007, a $5 million deposit was made into a CVO trust for the net after-tax cash flows generated by the four Earthco synthetic fuels facilities in 2004. Deposits into the trust will be classified as a restricted cash asset until the applicable tax years are closed, at which time a payment will be disbursed to the CVO holders. Future payments will include principal and interest earned during the investment period net of expenses deducted. The interest earned on the payment held in trust for 2007 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheet at December 31, 2007.

16. BENEFIT PLANS

A. POSTRETIREMENT BENEFITS

We have noncontributory defined benefit retirement plans for substantially all full-time employees that provide pension benefits. 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 components of the net periodic benefit cost for the years ended December 31 were:

Progress Energy

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2007**	2006	2005	**2007**	2006	2005
Service cost	**$46**	$45	$47	**$7**	$9	$9
Interest cost	**123**	117	117	**32**	33	33
Expected return on plan assets	**(155)**	(148)	(147)	**(6)**	(6)	(5)
Amortization of actuarial loss[a]	**15**	18	21	**2**	4	6
Other amortization, net [a]	**2**	–	–	**5**	5	5
Net periodic cost	**$31**	$32	$38	**$40**	$45	$48

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

In addition to the net periodic cost reflected above, in 2005, we recorded costs for special termination benefits related to a voluntary enhanced retirement program of $123 million for pension benefits and $19 million for other postretirement benefits.

We and the Utilities adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)," (SFAS No. 158) as of December 31, 2006. SFAS No. 158 amended prior accounting requirements for pension and OPEB plans. Prior to the implementation of SFAS No. 158, other comprehensive income (OCI) reflected minimum pension adjustments related to our pension plans. Our pre-tax minimum pension adjustments recognized as a component of OCI for the years ended December 31, 2006 and 2005 were net actuarial gains (losses) of $78 million and $(41) million, respectively. No amounts related to our OPEB plans were recognized as a component of OCI for the years ended December 31, 2006 and 2005. The table below provides a summary of amounts recognized in other comprehensive income for 2007 and other comprehensive income reclassification adjustments for amounts included in net income for 2007. The table also includes comparable items that affected regulatory assets of PEC and PEF. Refer to the PEC and PEF sections below for more information with regard to these regulatory assets.

(in millions)	Pension	Other Postretirement Benefits
Other comprehensive income (loss)		
Recognized for the year		
Net actuarial gain	$24	$16
Other, net	(1)	–
Reclassification adjustments		
Net actuarial loss	2	–
Other, net	1	
Regulatory asset (increase) decrease		
Recognized for the year		
Net actuarial gain	66	82
Other, net	(8)	–
Amortized to income		
Net actuarial loss	13	2
Other, net	1	4

PEC

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2007**	2006	2005	**2007**	2006	2005
Service cost	**$23**	$22	$22	**$5**	$4	$4
Interest cost	**56**	52	53	**15**	17	17
Expected return on plan assets	**(60)**	(59)	(62)	**(4)**	(4)	(4)
Amortization of actuarial loss	**12**	11	10	**–**	2	5
Other amortization, net	**2**	1	1	**1**	1	1
Net periodic cost	**$33**	$27	$24	**$17**	$20	$23

In addition to the net periodic cost reflected above, in 2005, PEC recorded costs for special termination benefits related to a voluntary enhanced retirement program of $21 million for pension benefits and $8 million for other postretirement benefits.

No amounts related to PEC's OPEB plans were recognized as a component of OCI for the years ended December 31, 2006 and 2005. Pre-tax minimum pension adjustments recognized as a component of OCI for the years ended December 31, 2006 and 2005 were net actuarial gains (losses) of $59 million and $(19) million, respectively. In conjunction with the implementation of SFAS No. 158, amounts that would otherwise be recorded in OCI are recorded as adjustments to regulatory assets consistent with the recovery of the related costs through the ratemaking process. The table below provides a summary of amounts recognized in regulatory assets for 2007 and amounts amortized from regulatory assets to net income for 2007.

(in millions)	Pension	Other Postretirement Benefits
Regulatory asset (increase) decrease		
Recognized for the year		
Net actuarial gain	$26	$82
Other, net	(6)	–
Amortized to net income		
Net actuarial loss	12	–
Other, net	2	1

PEF

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2007**	2006	2005	**2007**	2006	2005
Service cost	**$16**	$16	$16	**$2**	$3	$3
Interest cost	**52**	49	48	**14**	14	13
Expected return on plan assets	**(84)**	(78)	(73)	**(1)**	(1)	(1)
Amortization of actuarial loss	**1**	3	8	**2**	1	2
Other amortization, net	**(1)**	(1)	(1)	**3**	4	4
Net periodic (benefit) cost	**$(16)**	$(11)	$(2)	**$20**	$21	$21

In addition to the net periodic cost and benefit reflected above, in 2005 PEF recorded costs for special termination benefits related to a voluntary enhanced retirement program of $84 million for pension benefits and $7 million for other postretirement benefits.

No amounts related to PEF's OPEB or pension plans were recorded as a component of OCI for the years ended December 31, 2007, 2006 and 2005. Amounts that would otherwise be recorded in OCI are recorded as adjustments to regulatory assets consistent with the recovery of the related costs through the ratemaking process. The table below provides a summary of amounts recognized in regulatory assets for 2007 and amounts amortized from regulatory assets to net income for 2007.

(in millions)	Pension	Other Postretirement Benefits
Regulatory asset (increase) decrease		
Recognized for the year		
Net actuarial gain	$40	$–
Other, net	(1)	–
Amortized to net income		
Net actuarial loss	1	2
Other, net	(1)	3

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

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	**2007**	2006	2005
Discount rate	**5.95%**	5.65%	5.70%	**5.95%**	5.65%	5.70%
Rate of increase in future compensation						
Bargaining	**4.25%**	3.50%	3.50%	–	–	–
Supplementary plans	**5.25%**	5.25%	5.25%	–	–	–
Expected long-term rate of return on plan assets	**9.00%**	9.00%	9.00%	7.70%	8.30%	8.25%

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 9.00% for PEC and 5.00% for PEF, for all years presented.

The expected long-term rates of return on plan assets were determined by considering long-term historical returns for the plans and long-term projected returns based on the plans' target asset allocation. For all pension plan assets and a substantial portion of OPEB plans assets, those benchmarks support an expected long-term rate of return between 9.0% and 9.5%. The Progress Registrants used an expected long-term rate of 9.0%, the low end of the range, for 2007, 2006 and 2005.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

SFAS No. 158 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, 2007 and 2006 are presented in the tables below, with each table followed by related supplementary information.

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Projected benefit obligation at January 1	**$2,123**	$2,164	**$628**	$650
Service cost	**46**	45	**7**	9
Interest cost	**123**	117	**32**	33
Benefit payments	**(131)**	(174)	**(30)**	(29)
Plan amendment	**8**	18	**–**	(4)
Actuarial gain	**(27)**	(47)	**(96)**	(31)
Obligation at December 31	**2,142**	2,123	**541**	628
Fair value of plan assets at December 31	**1,996**	1,836	**75**	74
Funded status	**$(146)**	$(287)	**$(466)**	$(554)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $463 million and $2.123 billion at December 31, 2007 and 2006, respectively. Those plans had accumulated benefit obligations totaling $422 million and $2.083 billion at December 31, 2007 and 2006, respectively, and plan assets of $269 million and $1.836 billion at December 31, 2007 and 2006, respectively. The total accumulated benefit obligation for pension plans was $2.100 billion and $2.083 billion at December 31, 2007 and 2006, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Noncurrent assets	**$48**	$–	**$–**	$–
Current liabilities	**(10)**	(14)	**–**	(1)
Noncurrent liabilities	**(184)**	(273)	**(466)**	(553)
Funded status	**$(146)**	$(287)	**$(466)**	$(554)

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)	**2007**	2006	**2007**	2006
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	**$22**	$49	**$(9)**	$7
Other, net	**6**	5	**1**	1
Recognized in regulatory assets, net				
Net actuarial loss	**136**	215	**25**	108
Other, net	**28**	22	**23**	28
Total not yet recognized as a component of net periodic cost[(a)]	**$192**	$291	**$40**	$144

(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 2008.

(in millions)	Pension	Other Postretirement Benefits
Amortization of actuarial loss [(a)]	$7	$1
Amortization of other, net[(a)]	2	5

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

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Projected benefit obligation at January 1	**$952**	$969	**$330**	$333
Service cost	**23**	22	**5**	4
Interest cost	**56**	52	**15**	17
Plan amendment	**6**	9	**–**	–
Benefit payments	**(60)**	(83)	**(12)**	(11)
Actuarial (gain) loss	**3**	(17)	**(81)**	(13)
Obligation at December 31	**980**	952	**257**	330
Fair value of plan assets at December 31	**805**	741	**44**	45
Funded status	**$(175)**	$(211)	**$(213)**	$(285)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $980 million and $952 million at December 31, 2007 and 2006, respectively. Those plans had accumulated benefit obligations totaling $974 million and $946 million at December 31, 2007 and 2006, respectively, and plan assets of $805 million and $741 million at December 31, 2007 and 2006, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Current liabilities	**$(2)**	$(2)	**$ –**	$ –
Noncurrent liabilities	**(173)**	(209)	**(213)**	(285)
Funded status	**$(175)**	$(211)	**$(213)**	$(285)

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)	**2007**	2006	**2007**	2006
Recognized in regulatory assets				
Net actuarial loss (gain)	**$104**	$142	**$(12)**	$69
Other, net	**29**	25	**5**	7
Total not yet recognized as a component of net periodic cost	**$133**	$167	**$(7)**	$76

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2008.

(in millions)	Pension	Other Postretirement Benefits
Amortization of actuarial loss	$5	$–
Amortization of other, net	2	1

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Projected benefit obligation at January 1	**$880**	$896	**$246**	$259
Service cost	**16**	16	**2**	3
Interest cost	**52**	49	**14**	14
Plan amendment	**1**	8	**–**	(4)
Benefit payments	**(57)**	(69)	**(16)**	(17)
Actuarial gain	**(11)**	(20)	**(1)**	(9)
Obligation at December 31	**881**	880	**245**	246
Fair value of plan assets at December 31	**1,026**	952	**26**	24
Funded status	**$145**	$72	**$(219)**	$(222)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $345 million and $342 million at December 31, 2007 and 2006, respectively. Those plans had accumulated benefit obligations totaling $313 million and $311 million at December 31, 2007 and 2006, respectively, and plan assets of $269 million and $240 million at December 31, 2007 and 2006, respectively. The total accumulated benefit obligation for pension plans was $849 million December 31, 2007 and 2006.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Noncurrent assets	**$221**	$174	**$ –**	$ –
Current liabilities	**(3)**	(3)	**–**	–
Noncurrent liabilities	**(73)**	(99)	**(219)**	(222)
Funded status	**$145**	$72	**$(219)**	$(222)

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)	**2007**	2006	**2007**	2006
Recognized in regulatory assets, net				
Net actuarial loss	**$32**	$72	**$37**	$39
Other, net	**(1)**	(2)	**18**	21
Total not yet recognized as a component of net periodic cost	**$31**	$70	**$55**	$60

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2008.

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

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

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	**2007**	2006
Discount rate	**6.20%**	5.95%	**6.20%**	5.95%
Rate of increase in future compensation				
Bargaining	**4.25%**	4.25%	**–**	–
Supplementary plans	**5.25%**	5.25%	**–**	–
Initial medical cost trend rate for pre-Medicare Act benefits	**–**	–	**9.00%**	9.00%
Initial medical cost trend rate for post-Medicare Act benefits	**–**	–	**9.00%**	9.00%
Ultimate medical cost trend rate	**–**	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	**–**	–	**2015**	2014

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 as defined in EITF Issue No. 03-4, "Determining the Classification and Benefit Attribution Method for a 'Cash Balance' Pension Plan." Therefore, effective December 31, 2003, we began to 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	31	15	14
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(2)	(1)	(1)
Effect on postretirement benefit obligation	(26)	(12)	(12)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our, PEC's and PEF's employer contributions for 2007 include contributions directly to pension plan assets of $63 million, $33 million and $15 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, 30 percent for PEC and 15 percent for PEF. The OPEB benefits payments are also reduced by prescription drug-related federal subsidies received. In 2007, the subsidies totaled $3 million for us, $1 million for PEC and $2 million for PEF. In 2006, the subsidies totaled $2 million for us, $1 million for PEC and $1 million for PEF.

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

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Fair value of plan assets at January 1	**$1,836**	$1,770	**$74**	$76
Actual return on plan assets	**219**	222	**7**	8
Benefit payments	**(131)**	(174)	**(30)**	(29)
Employer contributions	**72**	18	**24**	19
Fair value of plan assets at December 31	**$1,996**	$1,836	**$75**	$74

PEC

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2007	2006	**2007**	2006
Fair value of plan assets at January 1	**$741**	$731	**$45**	$49
Actual return on plan assets	**89**	91	**5**	6
Benefit payments	**(60)**	(83)	**(12)**	(11)
Employer contributions	**35**	2	**6**	1
Fair value of plan assets at December 31	**$805**	$741	**$44**	$45

PEF

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2007	2006	**2007**	2006
Fair value of plan assets at January 1	**$952**	$895	**$24**	$22
Actual return on plan assets	**113**	114	**1**	1
Benefit payments	**(57)**	(69)	**(16)**	(17)
Employer contributions	**18**	12	**17**	18
Fair value of plan assets at December 31	**$1,026**	$952	**$26**	$24

The asset allocation for the benefit plans at the end of 2007 and 2006 and the target allocation for the plans, by asset category, are presented in the following tables. The pension benefit plan allocations and targets are consistent for all Progress Registrants.

	Pension Benefits		
	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2008	**2007**	2006
Equity – domestic	40%	**42%**	44%
Equity – international	15%	**25%**	23%
Debt – domestic	20%	**11%**	12%
Debt – international	10%	**12%**	9%
Other	15%	**10%**	12%
Total	100%	**100%**	100%

	Other Postretirement Benefits		
Progress Energy	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2008	**2007**	2006
Equity – domestic	25%	**28%**	30%
Equity – international	10%	**16%**	15%
Debt – domestic	50%	**41%**	40%
Debt – international	5%	**8%**	7%
Other	10%	**7%**	8%
Total	100%	**100%**	100%

PEC	Target Allocations	Percentage of Plan Assets	
Asset Category	2008	2007	2006
Equity – domestic	40%	**42%**	44%
Equity – international	15%	**25%**	23%
Debt – domestic	20%	**11%**	12%
Debt – international	10%	**12%**	9%
Other	15%	**10%**	12%
Total	100%	**100%**	100%

PEF	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2008	**2007**	2006
Debt – domestic	100%	**100%**	100%

For pension plan assets and a substantial portion of OPEB plan assets, the Progress Registrants set target allocations among asset classes to provide broad diversification to protect against large investment losses and excessive volatility, while recognizing the importance of offsetting the impacts of benefit cost escalation. In addition, external investment managers who have complementary investment philosophies and approaches are employed to manage the assets. 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.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2008, we expect to make $34 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 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $149, $153, $155, $157, $164 and $877, respectively. The expected benefit payments for the OPEB plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $37, $40, $43, $45, $47 and $247, 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 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $3, $3, $4, $4, $5 and $39, respectively.

In 2008, PEC expects to make $24 million in contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $73, $76, $78, $78, $81 and $426, respectively. The expected benefit payments for the OPEB plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $16, $17, $19, $20, $22, and $121, 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 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $1, $2, $2, $2, $2 and $17, respectively.

In 2008, PEF does not expect to make 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 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $56, $57, $58, $59, $61 and $334, respectively. The expected benefit payments for the OPEB plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $19, $20, $21, $22, $22 and $108, 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 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $2, $2, $2, $2, $2 and $14, 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 reviews using, among other things, 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.

As discussed in Note 15, in connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. 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, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively.

A. COMMODITY DERIVATIVES

GENERAL

Most of our physical commodity contracts are not derivatives pursuant to SFAS No. 133 or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the provisions of FASB Derivatives Implementation Group Issue C20, "Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature" (DIG Issue C20). The related liability is being amortized to earnings over the term of the related contract (See Note 20). At December 31, 2007 and 2006, the remaining liability was $10 million and $14 million, respectively.

DISCONTINUED OPERATIONS

As discussed in Note 3A, our subsidiary, PVI, entered into a series of transactions to sell or assign substantially all of its CCO physical and commercial assets and liabilities. On June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of 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. The sale of the generation assets closed on June 11, 2007. Additionally, we sold Gas on October 2, 2006 (See Note 3C). At December 31, 2007, with the exception of the oil price hedge instruments discussed below, our discontinued operations did not have outstanding positions in derivative instruments. 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 were included in discontinued operations on the Consolidated Statements of Income.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. 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 on January 8, 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Notes 1C and 3J, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate Ceredo in accordance with FIN 46R, but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. At December 31, 2007, the fair value of all of these contracts was recorded as a $234 million short-term derivative asset position, including $79 million at Ceredo. The fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet (See Note 6A). As discussed in Note 3B, on October 12, 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. 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 minority interest for the portion of the gain subsequent to the disposal of Ceredo.

At December 31, 2006, derivative assets of $107 million and derivative liabilities of $31 million were included in assets to be divested and liabilities to be divested, respectively, on the Consolidated Balance Sheet. Due to the divestitures discussed above, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts would be fulfilled, and cash flow hedge accounting for the contracts was discontinued beginning in the second quarter of 2006 for Gas and in the fourth quarter of 2006 for CCO. Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. For the years ended December 31, 2006 and 2005, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ended December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ended December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges.

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. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets on the Balance Sheets, respectively, until the contracts are settled (See Note 7A). Once settled, any realized gains or losses are passed through the fuel clause. During the year ended December 31, 2007, PEC recorded a net realized loss of $9 million. PEC's net realized gains and losses were not material during the years ended December 31, 2006 and 2005. During the years ended December 31, 2007, 2006 and 2005, PEF recorded a net realized loss of $46 million, a net realized gain of $39 million and a net realized gain of $70 million, respectively.

Excluding amounts receiving regulatory accounting treatment and amounts related to our discontinued operations discussed above, gains and losses from contracts entered into for economic hedging purposes were not material to our or the Utilities' results of operations during the years ended December 31, 2007, 2006 and 2005. Excluding derivative assets and derivative liabilities to be divested discussed above, we did not have material outstanding positions in such contracts at December 31, 2007 and 2006, other than those receiving regulatory accounting treatment at PEC and PEF, as discussed below.

At December 31, 2007, the fair value of PEC's commodity derivative instruments was recorded as a $19 million long-term derivative asset position included in other assets and deferred debits and a $3 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, PEC did not have material outstanding positions in such contracts.

At December 31, 2007, the fair value of PEF's commodity derivative instruments was recorded as a $60 million short-term derivative asset position included in prepayments and other current assets, a $90 million long-term derivative asset position included in derivative assets, and a $15 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, the fair value of such instruments was recorded as a $2 million long-term derivative asset position included in derivative assets, an $87 million short-term derivative liability position included in other current liabilities, and a $36 million long-term derivative liability position included in other liabilities and deferred credits on the Consolidated Balance Sheet.

CASH FLOW HEDGES

PEC designates a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to 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. PEF did not have any commodity derivative instruments designated as cash flow hedges at December 31, 2007 and 2006. At December 31, 2007 and 2006, we and PEC did not have 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 2007, 2006 and 2005.

At December 31, 2007 and 2006, the amount recorded in our or PEC's accumulated other comprehensive income related to commodity cash flow hedges was not material. PEF had no amount recorded in accumulated other comprehensive income related to commodity cash flow hedges at December 31, 2007 or 2006.

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. 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

The fair values of open interest rate cash flow hedges at December 31 were as follows:

	Progress Energy		PEC		PEF	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Fair value of liabilities	**$(12)**	$(2)	**$(12)**	$(1)	**$–**	$(1)

Gains and losses from cash flow hedges are recorded in accumulated other comprehensive income and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The ineffective portion of interest rate cash flow hedges was not material to our or the Utilities' results of operations for 2007, 2006 and 2005.

The following table presents selected information related to interest rate cash flow hedges included in accumulated other comprehensive income at December 31, 2007:

(term in years/millions of dollars)	Progress Energy	PEC	PEF
Maximum term	Less than 1	Less than 1	–
Accumulated other comprehensive loss, net of tax[(a)]	$(24)	$(12)	$(8)
Portion expected to be reclassified to earnings during the next 12 months[(b)]	$(2)	$(1)	$(1)

(a) Includes amounts related to terminated hedges.

(b) Actual amounts that will be reclassified to earnings may vary from the expected amounts presented above as a result of changes in interest rates.

At December 31, 2006, including amounts related to terminated hedges, we had $14 million of after-tax deferred losses, including $5 million of after-tax deferred losses at PEC and $1 million of after-tax deferred losses at PEF, recorded in accumulated other comprehensive income related to interest rate cash flow hedges.

At December 31, 2007 and 2006, PEC had $200 million notional and $50 million notional, respectively, of interest rate cash flow hedges. During 2007, PEC entered into a combined $150 million notional of forward starting swaps and amended its $50 million notional 10-year forward starting swap in order to move the maturity date from October 1, 2017 to April 1, 2018, which now requires mandatory cash settlement on April 1, 2008.

In 2007, PEF entered into a combined $225 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. At December 31, 2006, PEF had $50 million notional of interest rate cash flow hedges. All of PEF's forward starting swaps were terminated on September 13, 2007, in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. On January 8, 2008, PEF entered into a combined $200 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

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, 2007, we had no open interest rate fair value hedges. At December 31, 2006, we had $50 million notional of interest rate fair value hedges. At December 31, 2007 and 2006, the Utilities had no open interest rate fair value hedges.

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 include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2007, the Parent had issued $433 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). 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 PUHCA 1935. The repeal of PUHCA 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 2007, 2006 and 2005 to PEC amounted to $182 million, $188 million and $202 million, respectively, and services provided to PEF were $174 million, $165 million and $169 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2007, 2006 and 2005 amounted to $54 million, $34 million and $54 million, respectively. Services provided by PEF to PEC during 2007, 2006 and 2005 amounted to $10 million, $8 million and $14 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 5.49%, 5.17% and 3.77% at December 31, 2007, 2006 and 2005, 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.

Progress Fuels sold coal to PEF at cost in 2007 and 2006 and for an insignificant profit in 2005. These intercompany revenues and expenses are eliminated in consolidation; however, in accordance with SFAS No. 71, profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. Sales, net of insignificant profits, if any, of $2 million, $321 million and $402 million for the years ended December 31, 2007, 2006 and 2005, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income. In 2006, PEF began entering into coal contracts on its own behalf.

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 PEC and PEF business segments are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. These electric operations also distribute and sell electricity to other utilities, primarily in the eastern 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 disclosure requirements of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," as a separate business segment. The profit or loss of our reportable segments plus the profit or loss of Corporate and Other represents our total income from continuing operations.

Our former Coal and Synthetic Fuels segment was previously involved in the production and sale of coal-based solid synthetic fuels as defined under the Code, the operation of synthetic fuels facilities for third parties and coal terminal services. In 2007, we reclassified the operations of our synthetic fuels businesses and coal terminal services as discontinued operations (See Note 3B). For comparative purposes, prior year results have been restated to conform to the current segment presentation.

The postretirement and severance charges incurred in 2005 resulted from a workforce restructuring and voluntary enhanced retirement program that was approved in February 2005 and concluded in December 2005. Postretirement and severance charges reclassified to discontinued operations are not included in the table below.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between PEF and the former Coal and Synthetic Fuels segment, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and the former Coal and Synthetic Fuels segment are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. The profits realized for 2007, 2006 and 2005 were not significant. Prior to 2006, income tax expense (benefit) by segment includes the Parent's allocation to profitable subsidiaries of income tax benefits not related to acquisition interest expense in accordance with the Tax Agreement. Due to the repeal of PUHCA 1935, the Parent stopped allocating these tax benefits in 2006.

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
As of 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 and amortization	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
Segment profit (loss)	498	315	(120)	–	693
Total assets	11,962	10,004	16,383	(12,115)	26,234
Capital and investment expenditures	941	1,262	3	(2)	2,204

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2006					
Revenues					
Unaffiliated	$4,086	$4,638	$ –	$ –	$8,724
Intersegment	–	1	729	(730)	–
Total revenues	4,086	4,639	729	(730)	8,724
Depreciation and amortization	571	404	36	–	1,011
Interest income	25	15	85	(66)	59
Total interest charges, net	215	150	326	(67)	624
Income tax expense (benefit)	265	193	(119)	–	339
Segment profit (loss)	454	326	(229)	–	551
Total assets	12,020	8,593	15,421	(11,293)	24,741
Capital and investment expenditures	808	741	12	(9)	1,552

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2005					
Revenues					
Unaffiliated	$3,991	$3,955	$2	$ –	$7,948
Intersegment	–	–	839	(839)	–
Total revenues	3,991	3,955	841	(839)	7,948
Depreciation and amortization	561	334	31	–	926
Interest income	8	1	94	(90)	13
Total interest charges, net	192	126	342	(85)	575
Postretirement and severance charges	55	102	1	–	158
Income tax expense (benefit)	239	121	(62)	–	298
Segment profit (loss)	490	258	(225)	–	523
Total assets	11,502	8,318	18,278	(13,673)	24,425
Capital and investment expenditures	682	543	19	(19)	1,225

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income and other income and expense items as discussed 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. AFUDC equity represents the estimated equity costs of capital funds necessary to finance the construction of new regulated assets. The components of other, net as shown on the accompanying Statements of Income for the years ended December 31 were as follows:

Progress Energy

(in millions)	**2007**	2006	2005
Other income			
Nonregulated energy and delivery services income	**$36**	$41	$32
DIG Issue C20 amortization (Note 17A)	**4**	5	7
Contingent value obligation unrealized gain (Note 15)	**2**	–	6
Gain on sale of Level 3 stock [(a)]	**–**	32	–
Investment gains	**9**	4	4
Income from equity investments	**2**	1	1
AFUDC equity	**51**	21	16
Reversal of indemnification liability (Note 21B)	**–**	29	–
Other	**15**	13	16
Total other income	**119**	146	82
Other expense			
Nonregulated energy and delivery services expenses	**24**	27	23
Donations	**22**	20	18
Contingent value obligation unrealized loss (Note 15)	**4**	25	–
Investment losses	**4**	–	1
Loss from equity investments	**5**	3	7
Loss on debt redemption[(b)]	**–**	59	–
FERC audit settlement	**–**	–	7
Indemnification liability (Note 21B)	**–**	13	16
Other	**16**	15	11
Total other expense	**75**	162	83
Other, net – Progress Energy	**$44**	$(16)	$(1)

PEC

(in millions)	2007	2006	2005
Other income			
Nonregulated energy and delivery services income	**$14**	$15	$12
DIG Issue C20 amortization (Note 17A)	**4**	5	7
Investment gains	**4**	–	–
Income from equity investments	**1**	–	1
AFUDC equity	**10**	4	3
Reversal of indemnification liability (Note 21B)	**–**	29	–
Other	**11**	10	9
Total other income	**44**	63	32
Other expense			
Nonregulated energy and delivery services expenses	**8**	7	9
Donations	**9**	10	8
Investment losses	**3**	–	–
Losses from equity investments	**1**	1	–
FERC audit settlement	**–**	–	4
Indemnification liability (Note 21B)	**–**	13	16
Other	**7**	7	10
Total other expense	**28**	38	47
Other, net – PEC	**$16**	$25	$(15)

PEF

(in millions)	2007	2006	2005
Other income			
Nonregulated energy and delivery services income	**$24**	$26	$20
Investment gains	**2**	2	2
AFUDC equity	**41**	17	13
Other	**1**	1	–
Total other income	**68**	46	35
Other expense			
Nonregulated energy and delivery services expenses	**16**	20	14
Donations	**8**	10	10
Losses from equity investments	**1**	1	–
FERC audit settlement	**–**	–	3
Other	**4**	2	1
Total other expense	**29**	33	28
Other, net – PEF	**$39**	$13	$7

(a) Other income includes pre-tax gains of $32 million for the year ended December 31, 2006, from the sale of approximately 20 million shares of Level 3 stock received as part of the sale of our interest in PT LLC (See Note 3E). These gains are prior to the consideration of minority interest.

(b) On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008. On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 44.0 percent, of the aggregate principal amount of its 7.10% Senior Notes due March 1, 2011. We recognized a total pre-tax loss of $59 million in conjunction with these redemptions.

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 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 these potential claims cannot be predicted. No material claims are currently pending. 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 liabilities and deferred credits on the Balance Sheets, at December 31 were:

(in millions)	2007	2006
PEC		
MGP and other sites[(a)]	**$16**	$22
PEF		
Remediation of distribution and substation transformers	**31**	43
MGP and other sites	**17**	18
Total PEF environmental remediation accruals[(b)]	**48**	61
Progress Energy nonregulated operations	**–**	3
Total Progress Energy environmental remediation accruals	**$64**	$86

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

(b) Expected to be paid out over one to fifteen years.

PROGRESS ENERGY

In addition to the Utilities' sites, discussed under "PEC" and "PEF" below, our environmental sites include the following related to our nonregulated operations.

In 2001, we, through our Progress Fuels subsidiary, established an accrual to address indemnities and retained an environmental liability associated with the sale of our Inland Marine Transportation business. At December 31, 2006, the remaining accrual balance was approximately $3 million. For the year ended December 31, 2007, the accrual was reduced by approximately $3 million due to a reduction in the anticipated scope of work based on responses from regulatory agencies. Expenditures related to this liability were not material during 2007 and 2006.

On March 24, 2005, we completed the sale of our Progress Rail subsidiary. In connection with the sale, we incurred indemnity obligations related to certain pre-closing liabilities, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC

There are currently eight former MGP sites and a number of other sites associated with PEC that have required or are anticipated to require investigation and/or remediation. Three of these sites are in the long-term monitoring phase.

For the year ended December 31, 2007, including the Carolina Transformer site, the Ward Transformer site and MGP sites discussed below, PEC's accrual was reduced by a net amount of approximately $2 million and PEC spent approximately $4 million. For the year ended December 31, 2006, PEC accrued approximately $21 million and spent approximately $6 million. In October 2006, PEC received orders from the NCUC and SCPSC to defer and amortize certain environmental remediation expenses, net of insurance proceeds (See Note 7B).

For the year ended December 31, 2006, based upon newly available data for several of PEC's MGP sites, which had individual site remediation costs ranging from approximately $2 million to $4 million, a remediation liability of approximately $12 million was recorded for the minimum estimated total remediation cost for all of PEC's remaining MGP sites. The maximum amount of the range for all the sites cannot be determined at this time as one of the remaining sites is significantly larger than the sites for which we have historical experience. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

During the fourth quarter of 2004, the EPA advised PEC that it had been identified as a PRP at the Ward Transformer site located in Raleigh, N.C. The EPA offered PEC and a number of other PRPs the opportunity to negotiate cleanup of the site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the site. For the year ended December 31, 2006, based upon continuing assessment work performed at the site, PEC recorded an additional $9 million accrual for its portion of the estimated remediation costs. At December 31, 2006, after cumulative expenditures for the Ward site of approximately $3 million, PEC's recorded liability for the site was approximately $9 million. During 2007, the PRP agreement was amended to include an additional participating PRP, which reduced PEC's allocable share, and the estimated scope of work increased. These factors resulted in a net reduction to PEC's accrual for this site. At December 31, 2007, PEC's recorded liability for the site was approximately $6 million. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. The outcome of this matter cannot be predicted.

The EPA has also proposed, but not yet selected, a final remedial action plan to address stream segments downstream from the Ward Transformer site. The outcome of this matter cannot be predicted.

In September 2005, the EPA advised PEC that it had been identified as a PRP at the Carolina Transformer site located in Fayetteville, N.C. The EPA offered PEC and a number of other PRPs the opportunity to share in the reimbursement to the EPA of past expenditures in addressing conditions at the site, which are currently approximately $33 million. During the year ended December 31, 2007, a settlement was reached between the PRPs and the EPA, and PEC recorded and paid an immaterial amount for its share of the settlement.

PEF

PEF has received approval from the FPSC for recovery of the majority of costs associated with the remediation of distribution and substation transformers through the Environmental Cost Recovery Clause (ECRC). Under agreements with the Florida Department of Environmental Protection, PEF is in the process of examining distribution transformer sites and substation sites for mineral oil-impacted soil remediation caused by equipment integrity issues. PEF has reviewed a number of distribution transformer sites and all substation sites. Based on changes to the estimated time frame for inspections of distribution transformer sites, PEF currently expects to have completed this review by the end of 2008. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC. 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. For the year ended December 31, 2006, PEF accrued approximately $42 million due to additional sites expected to require remediation and spent approximately $19 million related to the remediation of transformers. At December 31, 2007, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

The amounts for MGP and other sites, in the table above, 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 amounts include approximately $12 million in insurance claim settlement proceeds received in 2004, which are restricted for use in addressing costs associated with environmental liabilities. For the year ended December 31, 2007, PEF made no accruals and spent approximately $1 million. For the year ended December 31, 2006, PEF made no accruals and PEF's expenditures were not material to our or PEF's results of operations or financial condition.

B. AIR AND WATER QUALITY

We are 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 include the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call), the Clean Smokestacks Act and mercury regulation (see "Other Matters – Environmental Matters" for discussion regarding Clean Air Mercury Rule (CAMR)). At December 31, 2007, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.567 billion, including $1.244 billion at PEC and $323 million at PEF. At December 31, 2006, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $932 million, including $904 million at PEC and $28 million at PEF.

As discussed in Note 7A, 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, 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. At December 31, 2007, and 2006, the amount of the liability was $30 million and $29 million, respectively, based upon the respective current estimates for Clean Smokestacks Act compliance. 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. In 2006, PEC notified the NCUC of its intent to record these estimated excess costs as part of the $569 million amortization required to be recorded by December 31, 2007, and accordingly, recorded the indemnification expense to Clean Smokestacks Act amortization. In a settlement agreement provisionally approved by the NCUC on December 20, 2007, eligible compliance costs in excess of the joint owner's share will be treated in the same manner as PEC's Clean Smokestacks Act compliance costs in excess of the original estimated compliance costs, as ultimately approved by the NCUC (See Note 7A).

22. COMMITMENTS AND CONTINGENCIES

A. PURCHASE OBLIGATIONS

At December 31, 2007, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2008	2009	2010	2011	2012	Thereafter
Fuel	$2,018	$1,745	$1,202	$1,001	$675	$5,103
Purchased power	455	422	409	443	415	3,756
Construction obligations	714	211	42	–	–	–
Other purchase obligations	94	39	32	16	16	64
Total	$3,281	$2,417	$1,685	$1,460	$1,106	$8,923

PEC

(in millions)	2008	2009	2010	2011	2012	Thereafter
Fuel	$958	$761	$664	$487	$308	$976
Purchased power	85	87	69	80	63	540
Construction obligations	84	22	–	–	–	–
Other purchase obligations	26	12	7	4	3	13
Total	$1,153	$882	$740	$571	$374	$1,529

PEF

(in millions)	2008	2009	2010	2011	2012	Thereafter
Fuel	$1,060	$984	$538	$514	$367	$4,127
Purchased power	370	335	340	363	352	3,216
Construction obligations	630	189	42	–	–	–
Other purchase obligations	56	20	19	12	12	50
Total	$2,116	$1,528	$939	$889	$731	$7,393

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel. Our payments under these commitments were $2.360 billion, $1.628 billion and $1.470 billion for 2007, 2006 and 2005, respectively. PEC's total payments under these commitments for its generating plants were $1.049 billion, $1.051 billion and $964 million in 2007, 2006 and 2005, respectively. PEF's payments totaled $1.311 billion, $577 million and $506 million in 2007, 2006 and 2005, respectively.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (primarily QFs) with expiration dates ranging from 2008 to 2030. These purchased power contracts generally provide for capacity and energy payments.

PEC has a long-term agreement for the purchase of power and related transmission services from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The agreement provides for the purchase of 250 MW of capacity through 2009 with estimated minimum annual payments of approximately $42 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $77 million, $80 million and $71 million for 2007, 2006 and 2005, respectively.

PEC executed two long-term agreements for the purchase of power from Broad River LLC's Broad River facility (Broad River). One agreement provides for the purchase of approximately 500 MW of capacity through 2021 with an original minimum annual payment of approximately $16 million, primarily representing capital-related capacity costs. The second agreement provided for the additional purchase of approximately 335 MW of capacity through 2022 with an original minimum annual payment of approximately $16 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River agreements amounted to $39 million, $40 million and $44 million in 2007, 2006 and 2005, respectively.

In 2007, PEC executed a long-term agreement for the purchase of power from Southern Power Company. The agreement provides for capacity purchases of 305 MW for 2010, 310 MW for 2011 and 150 MW annually thereafter through 2019. Estimated payments for capacity and energy under the agreement are $22 million for 2010, $33 million for 2011 and $14 million annually thereafter through 2019.

PEC has various pay-for-performance contracts with QFs for approximately 195 MW of capacity expiring at various times through 2014. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $95 million, $182 million and $112 million in 2007, 2006 and 2005, respectively.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $161 million, $162 million and $175 million for 2007, 2006 and 2005, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $70 million annually through 2011, $50 million for 2012 and $32 million annually thereafter through 2016.

PEF has ongoing purchased power contracts with certain QFs for 965 MW of capacity with expiration dates ranging from 2008 to 2030. 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 generating capacity of each of the facilities. All commitments, except one for 75 MW, have been approved by the FPSC. Total capacity purchases under these contracts amounted to $288 million, $277 million and $262 million for 2007, 2006 and 2005, respectively. At December 31, 2007, minimum expected future capacity payments under these contracts were $297 million, $263 million, $267 million, $281 million and $292 million for 2008 through 2012, respectively, and $3.053 billion 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 January 2006, PEF entered into a conditional contract with Gulfstream Natural Gas System, L.L.C. (Gulfstream) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from September 1, 2008, through January 1, 2031. The total cost to PEF associated with this agreement is approximately $777 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of the necessary related expansions to Gulfstream's natural gas pipeline system, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In July 2006, PEF entered into a conditional contract with Devon Gas Services for the supply of natural gas to augment PEF's gas supply needs for the period from May to September for the years 2008 through 2011. The total cost to PEF associated with this agreement is approximately $251 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate pipeline expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Cross Timbers Energy Services, Inc. for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2013. The total cost to PEF associated with this agreement is approximately $1.026 billion. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Southeast Supply Header, L.L.C. (SESH) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2023. The total cost to PEF associated with this agreement is approximately $271 million. The transaction is subject to several conditions precedent, including FPSC approval, the completion and commencement of operation of the SESH pipeline project, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with a private oil and gas company for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through March 31, 2013. The total cost to PEF associated with this agreement is approximately $146 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In January and February 2007, PEF entered into conditional contracts with Chevron Natural Gas for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, to May 31, 2013. The total cost to PEF associated with these agreements is approximately $935 million. The transactions are subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate pipeline expansions, and other standard closing conditions. Due to the conditions of these agreements the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $675 million, $365 million and $91 million for 2007, 2006 and 2005, respectively. PEC's future obligations related to Clean Smokestacks Act capital projects are $84 million for 2008 and $22 million for 2009. Total payments under PEC's contracts related to Clean Smokestacks Act projects were $208 million and $225 million for 2007 and 2006, respectively. PEC did not have any payments related to construction obligations in 2005. PEF has purchase obligations related to various capital projects related to new generation and Florida CAIR. Total payments under PEF's contracts were $467 million, $140 million and $91 million for 2007, 2006 and 2005, respectively. PEF's future obligations under these contracts are $631 million, $188 million and $42 million for 2008 through 2010, 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 a PEF service agreement related to the Hines Energy Complex. Our payments under these agreements were $97 million, $122 million and $100 million for 2007, 2006 and 2005, respectively.

We have entered into various other contractual obligations primarily related to capacity and service contracts for operational services associated with discontinued CCO operations. Total payments under these contracts were $8 million, $18 million and $17 million for 2007, 2006 and 2005, respectively. Estimated future payments under these contracts of $6 million are not reflected in the contractual cash obligations table above. Included in these contracts are purchase obligations with a counterparty for pipeline capacity through 2009.

PEC has various purchase obligations for emission obligations, limestone supply and the purchase of capital parts. Total purchases under these contracts were $21 million, $2 million and $10 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $22 million for 2008, $4 million each for 2009 and 2010, and $3 million each for 2011 and 2012 and $13 million thereafter.

PEC has various purchase obligations related to reactor vessel head replacements, power uprates and spent fuel storage. Total purchases under these contracts were $8 million for 2006 and $13 million for 2005, with no purchases in 2007. Future obligations under these contracts are for spent fuel storage and total $5 million, $8 million, $3 million and $1 million for 2008 through 2011, respectively.

PEF has long-term service agreements for the Hines Energy Complex. Total payments under these contracts were $11 million, $12 million and $8 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $21 million, $14 million, $19 million, $12 million and $12 million for 2008 through 2012, respectively, with approximately $50 million payable thereafter.

PEF has various purchase obligations and contractual commitments related to the purchase and replacement of machinery. Total payments under these contracts were $22 million, $21 million and $34 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $8 million and $6 million for 2008 and 2009, respectively.

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 $40 million, $42 million and $38 million for 2007, 2006 and 2005, respectively. Our purchased power expense under agreements classified as operating leases was approximately $69 million, $60 million and $14 million in 2007, 2006 and 2005, respectively.

PEC's rent expense under operating leases totaled $23 million, $25 million and $24 million during 2007, 2006 and 2005, respectively. These amounts include rent expense allocated from PESC to PEC of $6 million, $8 million and $7 million for 2007, 2006 and 2005, respectively. Purchased power expense under agreements classified as operating leases was approximately $10 million, $10 million and $11 million in 2007, 2006 and 2005, respectively.

PEF's rent expense under operating leases totaled $15 million, $16 million and $11 million during 2007, 2006 and 2005, respectively. These amounts include rent expense allocated from PESC to PEF of $6 million for 2007 and $7 million each for 2006 and 2005. Purchased power expense under agreements classified as operating leases was approximately $59 million, $49 million and $3 million in 2007, 2006 and 2005, respectively.

Assets recorded under capital leases at December 31 consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Buildings	**$267**	$84	**$30**	$30	**$237**	$54
Less: Accumulated amortization	**(20)**	(12)	**(13)**	(12)	**(7)**	–
Total	**$247**	$72	**$17**	$18	**$230**	$54

At December 31, 2007, 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
2008	$28	$62	$2	$35	$26	$22
2009	29	41	3	30	26	6
2010	28	25	2	17	26	4
2011	28	20	2	13	26	4
2012	28	38	2	13	26	23
Thereafter	308	554	10	127	298	424
Minimum annual payments	449	$740	21	$235	428	$483
Less amount representing imputed interest	(202)		(4)		(198)	
Present value of net minimum lease payments under capital leases	$247		$17		$230	

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 2007, PEF entered into a purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $28 million from 2012 through 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 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 an agreement for purchased power, which is classified as a capital lease, for an additional 10 years.

The agreement calls for minimum annual payments of approximately $21 million from 2007 through 2024 for a total of approximately $348 million. Due to the conditions of the agreement, the capital lease was not recorded on our or PEF's Balance Sheets until 2007.

In 2006, PEF entered into an agreement for purchased power, which is classified as a capital lease. Due to the conditions of the agreement, the capital lease will not be recorded on PEF's Balance Sheet until approximately 2011. Therefore, this capital lease is not included in the table above. The agreement calls for minimum annual payments of approximately $8 million from 2012 through 2036 for a total of approximately $208 million.

Excluding the Utilities, we are also a lessor of land, buildings and other types of properties we own under operating leases with various terms and expiration dates. The leased buildings are depreciated under the same terms as other buildings included in diversified business property. Minimum rentals receivable under noncancelable leases are approximately $8 million, $7 million, $5 million, $4 million and $2 million for 2008 through 2012, respectively. Rents received under these operating leases totaled $8 million, $9 million and $8 million for 2007, 2006 and 2005, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $10 million for 2008 and none thereafter. PEC's rents received are contingent upon usage and totaled $33 million for 2007 and $31 million each for 2006 and 2005. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $78 million, $72 million and $63 million for 2007, 2006 and 2005, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2008 and thereafter.

C. GUARANTEES

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties, which are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2007, 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 Balance Sheets.

At December 31, 2007, 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, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations, which are within the scope of FIN 45. Related to the sales of businesses, the latest notice period extends until 2012 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. 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 (See Note 21B). PEC's maximum exposure cannot be determined. At December 31, 2007, the estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $427 million, including $32 million at PEF. At December 31, 2007 and 2006, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $80 million and $60 million, respectively. These amounts include $30 million and $29 million, respectively, for PEC and $8 million for PEF at December 31, 2007 and 2006. 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. Our damages due to the DOE's breach will be significant, but have yet to be determined. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims.

The DOE and the Utilities agreed to, and the trial court entered, a stay of proceedings, in order to allow for possible efficiencies due to the resolution of legal and factual issues in previously filed cases in which similar claims are being pursued by other plaintiffs. These issues may include, among others, so-called "rate issues," or the minimum mandatory schedule for the acceptance of spent nuclear fuel and high-level radioactive waste by which the government was contractually obligated to accept contract holders' spent nuclear fuel and/or high-level waste, and issues regarding recovery of damages under a partial breach of contract theory that will be alleged to occur in the future. These issues have been presented in the trials or appeals during 2006 and 2007. Resolution of these issues in other cases could facilitate agreements by the parties in the Utilities' lawsuit, or at a minimum, inform the court of decisions reached by other courts if they remain contested and require resolution in this case. In July 2005, the parties jointly requested a continuance of the stay through December 15, 2005, which the trial court granted. Subsequently, the trial court continued the stay until March 17, 2006. The trial court lifted the stay on March 22, 2006, and discovery commenced. The trial court issued a scheduling order on March 23, 2006, and the case went to trial beginning November 5, 2007. Closing arguments are anticipated in the second quarter of 2008 with a ruling expected later in 2008. The Utilities cannot predict the outcome of this matter. 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.

In July 2002, Congress passed an override resolution to Nevada's veto of the DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nev. In January 2003, the state of Nevada; Clark County, Nev.; and the city of Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged the EPA's radiation standards for Yucca Mountain. On July 9, 2004, the Court rejected the challenge to the constitutionality of the resolution approving Yucca Mountain, but ruled that the EPA was wrong to set a 10,000-year compliance period in the radiation protection standard. In August 2005, the EPA issued new proposed standards. The proposed standards include a 1,000,000-year compliance period in the radiation protection standard. Comments were due November 21, 2005, and are being reviewed by the EPA. The DOE originally planned to submit a license application to the NRC to construct the Yucca Mountain facility by the end of 2004. However, in November 2004, the DOE announced it would not submit the license application until mid-2005 or later. The DOE did not submit the license application in 2005 and subsequently reported that the license application would be submitted by June 2008 if full funding was obtained for the project. The DOE requested $545 million for fiscal year 2007 and received $445 million. The DOE requested $495 million for fiscal year 2008. However, Congress passed an appropriations bill which allocates $390 million in fiscal year 2008 for DOE's Yucca Mountain repository program. As a result of the fiscal year budget reductions, the schedule for submitting the license application is being re-evaluated by the DOE. The impact to the Yucca Mountain repository program cannot be predicted at this time.

On October 19, 2007, the DOE certified the regulatory compliance of the document database that will be used by all parties involved in the federal licensing process for the Yucca Mountain facility. The NRC did not uphold the DOE's prior certification in 2004 in response to challenges from the state of Nevada. The state again is expected to challenge the DOE's certification process. The DOE has stated that if legislative changes requested by the Bush administration are enacted, the repository may be able to accept spent nuclear fuel starting in 2017, but 2020 is more probable due to anticipated litigation by the state of Nevada. The Utilities cannot predict the outcome of this matter.

With certain modifications and additional approvals by the NRC, including the installation of on-site dry cask storage facilities at Robinson, Brunswick and CR3, the Utilities' spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on their respective systems through the expiration of the operating licenses, including any license extensions, for their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pools through the expiration of its operating license, including any license extensions.

SYNTHETIC FUELS MATTERS

A number of our subsidiaries and affiliates are parties to two lawsuits arising out of an Asset Purchase Agreement dated as of October 19, 1999, by and among U.S. Global, LLC (Global); the Earthco synthetic fuels facilities (Earthco); certain affiliates of Earthco; EFC Synfuel LLC (which is 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 Purchase Agreement as of August 23, 2000 (the Asset Purchase Agreement). Global has asserted (1) that pursuant to the Asset Purchase Agreement, it is entitled to an interest in two synthetic fuels facilities currently owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it is entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities and (3) a number of tort claims related to the contracts.

The first suit, *U.S. Global, LLC v. Progress Energy, Inc. et al.* (the Florida Global Case), asserts the above claims in a case filed in the Circuit Court for Broward County, Fla., in March 2003, and requests an unspecified amount of compensatory damages, as well as declaratory relief. The Progress Affiliates have answered the Complaint by generally denying all of Global's substantive allegations and asserting numerous substantial affirmative defenses. The case is at issue, but neither party has requested a trial. The parties are currently engaged in discovery in the Florida Global Case.

The second suit, *Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC* (the North Carolina Global Case), was filed by the Progress Affiliates in the Superior Court for Wake County, N.C., seeking 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. Since that time, the parties have been engaged in discovery in the Florida Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the suit 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.

In January 2008, Global agreed to simplify the Florida action by dismissing the tort claims. The suit continues now under contract theories alone. 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 in accordance with SFAS No. 5 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 yearly 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. As of December 31, 2007, 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 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a special-purpose entity and in accordance with the provisions of FIN 46R, we deconsolidated the Trust on December 31, 2003. The deconsolidation was not material to our financial statements. 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 the following tables, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the financial results of Florida Progress. The Other column includes the consolidated financial results of all other nonguarantor subsidiaries and elimination entries for all intercompany transactions. All applicable corporate expenses have been allocated appropriately among the guarantor and nonguarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other nonguarantor subsidiaries operated as independent entities. The accompanying condensed consolidating financial statements have been restated for all periods presented to reflect the operations of Terminals and the synthetic fuels businesses as discontinued operations as described in Note 3B.

Condensed Consolidating Statement of Income
Year ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$–	$4,768	$4,385	$9,153
Affiliate revenues	–	89	(89)	–
Total operating revenues	–	4,857	4,296	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	998	1,842
Depreciation and amortization	–	369	536	905
Taxes other than on income	–	309	192	501
Other	–	20	10	30
Total operating expenses	10	4,178	3,419	7,607
Operating (loss) income	(10)	679	877	1,546
Other income, net	27	47	4	78
Interest charges, net	203	198	187	588
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(186)	528	694	1,036
Income tax (benefit) expense	(79)	117	296	334
Equity in earnings of consolidated subsidiaries	596	–	(596)	–
Minority interest in subsidiaries' income, net of tax	–	(9)	–	(9)
Income (loss) from continuing operations	489	402	(198)	693
Discontinued operations, net of tax	15	(59)	(145)	(189)
Net income (loss)	$504	$343	$(343)	$504

Condensed Consolidating Statement of Income
Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$–	$4,637	$4,087	$8,724
Affiliate revenues	–	41	(41)	–
Total operating revenues	–	4,678	4,046	8,724
Operating expenses				
Fuel used in electric generation	–	1,835	1,173	3,008
Purchased power	–	766	334	1,100
Operation and maintenance	14	684	885	1,583
Depreciation and amortization	–	406	605	1,011
Taxes other than on income	–	309	191	500
Other	–	21	14	35
Total operating expenses	14	4,021	3,202	7,237
Operating (loss) income	(14)	657	844	1,487
Other (expense) income, net	(33)	55	21	43
Interest charges, net	276	182	166	624
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	530	699	906
Income tax (benefit) expense	(123)	174	288	339
Equity in earnings of consolidated subsidiaries	779	–	(779)	–
Minority interest in subsidiaries' income, net of tax	–	(16)	–	(16)
Income (loss) from continuing operations	579	340	(368)	551
Discontinued operations, net of tax	(8)	359	(331)	20
Net income (loss)	$571	$699	$(699)	$571

Condensed Consolidating Statement of Income
Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$–	$3,956	$3,992	$7,948
Affiliate revenues	–	188	(188)	–
Total operating revenues	–	4,144	3,804	7,948
Operating expenses				
Fuel used in electric generation	–	1,323	1,036	2,359
Purchased power	–	694	354	1,048
Operation and maintenance	12	852	906	1,770
Depreciation and amortization	–	337	589	926
Taxes other than on income	4	279	177	460
Other	–	(5)	2	(3)
Total operating expenses	16	3,480	3,064	6,560
Operating (loss) income	(16)	664	740	1,388
Other income (expense), net	66	(1)	(53)	12
Interest charges, net	305	163	107	575
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(255)	500	580	825
Income tax (benefit) expense	(64)	96	266	298
Equity in earnings of consolidated subsidiaries	884	–	(884)	–
Minority interest in subsidiaries' income, net of tax	–	(4)	–	(4)
Income (loss) from continuing operations	693	400	(570)	523
Discontinued operations, net of tax	4	(26)	195	173
Cumulative effect of change in accounting principle, net of tax	–	–	1	1
Net income (loss)	$697	$374	$(374)	$697

Condensed Consolidating Balance Sheet
December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$–	$7,600	$9,005	$16,605
Current assets				
Cash and cash equivalents	185	43	27	255
Short-term investments	–	–	1	1
Notes receivable from affiliated companies	157	149	(306)	–
Deferred fuel cost	–	6	148	154
Assets to be divested	–	48	4	52
Prepayments and other current assets	21	1,211	1,081	2,313
Total current assets	363	1,457	955	2,775
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,969	–	(10,969)	–
Goodwill	–	1	3,654	3,655
Other assets and deferred debits	149	1,551	1,551	3,251
Total deferred debits and other assets	11,118	1,552	(5,764)	6,906
Total assets	$11,481	$10,609	$4,196	$26,286
Capitalization				
Common stock equity	$8,422	$3,052	$(3,052)	$8,422
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	81	3	84
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,597	2,686	3,183	8,466
Total capitalization	11,019	6,162	155	17,336
Current liabilities				
Current portion of long-term debt	–	577	300	877
Short-term debt	201	–	–	201
Notes payable to affiliated companies	–	227	(227)	–
Regulatory liabilities	–	173	–	173
Liabilities to be divested	–	8	–	8
Other current liabilities	215	1,028	746	1,989
Total current liabilities	416	2,013	819	3,248
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	59	302	361
Regulatory liabilities	–	1,316	1,223	2,539
Accrued pension and other benefits	12	347	404	763
Capital lease obligations	–	224	15	239
Other liabilities and deferred credits	34	488	1,278	1,800
Total deferred credits and other liabilities	46	2,434	3,222	5,702
Total capitalization and liabilities	$11,481	$10,609	$4,196	$26,286

Condensed Consolidating Balance Sheet
December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$6,337	$8,908	$15,245
Current assets				
Cash and cash equivalents	153	40	72	265
Short-term investments	21	–	50	71
Notes receivable from affiliated companies	58	37	(95)	–
Deferred fuel cost	–	–	196	196
Assets to be divested	–	121	845	966
Prepayments and other current assets	27	1,060	1,029	2,116
Total current assets	259	1,258	2,097	3,614
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,740	–	(10,740)	–
Goodwill	–	1	3,654	3,655
Other assets and deferred debits	126	1,556	1,511	3,193
Total deferred debits and other assets	10,866	1,557	(5,575)	6,848
Total assets	$11,125	$9,152	$5,430	$25,707
Capitalization				
Common stock equity	$8,286	$2,708	$(2,708)	$8,286
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	6	4	10
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,582	2,512	3,470	8,564
Total capitalization	10,868	5,569	787	17,224
Current liabilities				
Current portion of long-term debt	–	124	200	324
Notes payable to affiliated companies	–	77	(77)	–
Liabilities to be divested	–	72	176	248
Other current liabilities	210	1,224	814	2,248
Total current liabilities	210	1,497	1,113	2,820
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	61	251	312
Regulatory liabilities	–	1,091	1,452	2,543
Accrued pension and other benefits	14	377	566	957
Other liabilities and deferred credits	33	557	1,261	1,851
Total deferred credits and other liabilities	47	2,086	3,530	5,663
Total capitalization and liabilities	$11,125	$9,152	$5,430	$25,707

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$76	$489	$687	$1,252
Investing activities				
Gross property additions	–	(1,218)	(755)	(1,973)
Nuclear fuel additions	–	(44)	(184)	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	51	624	675
Purchases of available-for-sale securities and other investments	–	(640)	(773)	(1,413)
Proceeds from sales of available-for-sale securities and other investments	21	640	791	1,452
Changes in advances to affiliates	(99)	(112)	211	–
Return of investment in consolidated subsidiary	340	–	(340)	–
Other investing activities	(31)	32	29	30
Net cash provided (used) by investing activities	231	(1,291)	(397)	(1,457)
Financing activities				
Issuance of common stock	151	–	–	151
Dividends paid on common stock	(627)	–	–	(627)
Dividends paid to parent	–	(10)	10	–
Proceeds from issuance of short-term debt with original maturities greater than 90 days	176	–	–	176
Net increase in short-term debt	25	–	–	25
Proceeds from issuance of long-term debt, net	–	739	–	739
Retirement of long-term debt	–	(124)	(200)	(324)
Changes in advances from affiliates	–	151	(151)	–
Other financing activities	–	49	6	55
Net cash (used) provided by financing activities	(275)	805	(335)	195
Net increase (decrease) in cash and cash equivalents	32	3	(45)	(10)
Cash and cash equivalents at beginning of year	153	40	72	265
Cash and cash equivalents at end of year	$185	$43	$27	$255

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$1,295	$1,110	$(404)	$2,001
Investing activities				
Gross property additions	–	(865)	(707)	(1,572)
Nuclear fuel additions	–	(12)	(102)	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	1,242	415	1,657
Purchases of available-for-sale securities and other investments	(919)	(625)	(908)	(2,452)
Proceeds from sales of available-for-sale securities and other investments	898	724	1,009	2,631
Changes in advances to affiliates	409	(39)	(370)	–
Proceeds from repayment of long-term affiliate debt	131	–	(131)	–
Return of investment in consolidated subsidiaries	287	–	(287)	–
Other investing activities	(63)	(6)	46	(23)
Net cash provided (used) by investing activities	743	419	(1,035)	127
Financing activities				
Issuance of common stock	185	–	–	185
Dividends paid on common stock	(607)	–	–	(607)
Dividends paid to parent	–	(1,135)	1,135	–
Net decrease in short-term debt	–	(102)	(73)	(175)
Proceeds from issuance of long-term debt, net	397	–	–	397
Retirement of long-term debt	(2,091)	(109)	–	(2,200)
Retirement of long-term affiliate debt	–	(131)	131	–
Changes in advances from affiliates	–	(243)	243	–
Other financing activities	(8)	(8)	(52)	(68)
Net cash (used) provided by financing activities	(2,124)	(1,728)	1,384	(2,468)
Net decrease in cash and cash equivalents	(86)	(199)	(55)	(340)
Cash and cash equivalents at beginning of year	239	239	127	605
Cash and cash equivalents at end of year	$153	$40	$72	$265

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$257	$509	$701	$1,467
Investing activities				
Gross property additions	–	(714)	(599)	(1,313)
Nuclear fuel additions	–	(47)	(79)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	462	13	475
Purchases of available-for-sale securities and other investments	(1,702)	(405)	(1,878)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	1,702	405	1,738	3,845
Changes in advances to affiliates	333	5	(338)	–
Proceeds from repayment of long-term affiliate debt	369	–	(369)	–
Other investing activities	(12)	(26)	(2)	(40)
Net cash provided (used) by investing activities	690	(320)	(1,514)	(1,144)
Financing activities				
Issuance of common stock	208	–	–	208
Dividends paid on common stock	(582)	–	–	(582)
Dividends paid to parent	–	(2)	2	–
Net decrease in short-term debt	(170)	(191)	(148)	(509)
Proceeds from issuance of long-term debt, net	–	744	898	1,642
Retirement of long-term debt	(160)	(104)	(300)	(564)
Retirement of long-term affiliate debt	–	(369)	369	–
Changes in advances from affiliates	–	(101)	101	–
Other financing activities	(9)	50	(9)	32
Net cash (used) provided by financing activities	(713)	27	913	227
Net increase in cash and cash equivalents	234	216	100	550
Cash and cash equivalents at beginning of year	5	23	27	55
Cash and cash equivalents at end of year	$239	$239	$127	$605

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Results of operations for an interim period may not give a true indication of results for the year. In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Summarized quarterly financial data was as follows:

Progress Energy

(in millions except per share data)	First [(a)]	Second [(a)]	Third [(a)]	Fourth [(a)]
2007				
Operating revenues	**$2,072**	**$2,129**	**$2,750**	**$2,202**
Operating income	**351**	**301**	**610**	**284**
Income from continuing operations	**159**	**106**	**327**	**101**
Net income (loss)	**275**	**(193)**	**319**	**103**
Common stock data				
Basic earnings per common share				
Income from continuing operations	**0.63**	**0.42**	**1.27**	**0.39**
Net income (loss)	**1.08**	**(0.75)**	**1.24**	**0.40**
Diluted earnings per common share				
Income from continuing operations	**0.62**	**0.41**	**1.27**	**0.39**
Net income (loss)	**1.08**	**(0.75)**	**1.24**	**0.40**
Dividends declared per common share	**0.610**	**0.610**	**0.610**	**0.615**
Market price per share – High	**51.60**	**52.75**	**49.48**	**50.25**
– Low	**47.05**	**45.15**	**43.12**	**44.75**
2006				
Operating revenues	$1,985	$2,083	$2,599	$2,057
Operating income	295	332	570	290
Income from continuing operations	67	110	268	106
Net income (loss)	45	(47)	319	254
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.27	0.44	1.07	0.42
Net income (loss)	0.18	(0.19)	1.27	1.01
Diluted earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.27	0.44	1.07	0.42
Net income (loss)	0.18	(0.19)	1.27	1.01
Dividends declared per common share	0.605	0.605	0.605	0.610
Market price per share – High	45.31	45.16	46.22	49.55
– Low	42.54	40.27	42.05	44.40

(a) Operating results have been restated for discontinued operations.

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. The 2007 and 2006 amounts were restated for discontinued operations (See Note 3).

PEC

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2007				
Operating revenues	**$1,058**	**$996**	**$1,286**	**$1,045**
Operating income	**235**	**180**	**375**	**179**
Net income	**124**	**88**	**204**	**85**
2006				
Operating revenues	$978	$936	$1,200	$972
Operating income	189	174	346	178
Net income	86	76	189	106

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.

PEF

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2007				
Operating revenues	**$1,011**	**$1,129**	**$1,456**	**$1,153**
Operating income	**117**	**125**	**235**	**109**
Net income	**61**	**68**	**138**	**50**
2006				
Operating revenues	$1,007	$1,147	$1,399	$1,086
Operating income	117	167	237	122
Net income	53	87	125	63

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.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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.

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				

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (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	(111,569)		(111,569)		
2	19,986		19,986		
3	(1,443,435)		(1,443,435)		
4	(1,423,449)		(1,423,449)	328,236,391	326,812,942
5	(1,535,018)		(1,535,018)		
6	(1,535,018)		(1,535,018)		
7	151,545		151,545		
8	(6,982,325)		(6,982,325)		
9	(6,830,780)		(6,830,780)	317,330,866	310,500,086
10	(8,365,798)		(8,365,798)		

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	12/31/2007	End of 2007/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 (f) 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)	9,776,814,998	9,774,283,758
4	Property Under Capital Leases	230,109,671	230,109,671
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	10,006,924,669	10,004,393,429
9	Leased to Others		
10	Held for Future Use	35,089,957	35,089,957
11	Construction Work in Progress	1,191,510,032	1,191,510,032
12	Acquisition Adjustments	18,457,490	18,457,490
13	Total Utility Plant (8 thru 12)	11,251,982,148	11,249,450,908
14	Accum Prov for Depr, Amort, & Depl	4,540,773,297	4,539,485,330
15	Net Utility Plant (13 less 14)	6,711,208,851	6,709,965,578
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,421,851,627	4,421,851,627
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	121,899,724	120,611,757
22	Total In Service (18 thru 21)	4,543,751,351	4,542,463,384
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	-2,978,054	-2,978,054
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,540,773,297	4,539,485,330

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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
	1,287,967				14
	1,243,273				15
					16
					17
					18
					19
					20
	1,287,967				21
	1,287,967				22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
	1,287,967				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	12/31/2007	2007/Q4

FOOTNOTE DATA

Schedule Page: 200 Line No.: 6 Column: b

Column (b), line 6 - In Q2 2006, we began to include these dollars in line 3. It was determined that we should report dollars based on general ledger classification. Since any dollars for "Completed Construction Not Classified" is included with "Classified Plant In Service" in the same general ledger account, combining the two was deemed to be the proper treatment.

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	12/31/2007	End of 2007/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	12,481,913	27,434,703
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	12,481,913	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	610,437	56,646,494
9	In Reactor (120.3)	99,097,726	46,276,381
10	SUBTOTAL (Total 8 & 9)	99,708,163	
11	Spent Nuclear Fuel (120.4)		41,325,520
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	53,780,714	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	58,409,362	
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	12/31/2007	End of 2007/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.
[redacted]			1
[redacted]			2
[redacted]	34,879,877	5,036,739	3
[redacted]			4
[redacted]			5
[redacted]	[redacted]	5,036,739	6
[redacted]	[redacted]		7
	51,824,405	5,432,526	8
	41,325,520	104,048,587	9
[redacted]	[redacted]	109,481,113	10
		41,325,520	11
			12
-23,210,683		76,991,397	13
[redacted]	[redacted]	78,851,975	14
[redacted]	[redacted]		15
[redacted]	[redacted]		16
[redacted]	[redacted]		17
			18
			19
			20
			21
[redacted]	[redacted]		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	12/31/2007	2007/Q4

FOOTNOTE DATA

Schedule Page: 202 Line No.: 3 Column: e

$34,879,877 transferred to 120.2.

Schedule Page: 202 Line No.: 8 Column: e

$51,824,405 transferred to 120.1.

Schedule Page: 202 Line No.: 9 Column: e

$41,325,520 transferred to 120.4.

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	12/31/2007	End of 2007/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	8,450,029	
4	(303) Miscellaneous Intangible Plant	122,205,796	3,153,436
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	130,655,825	3,153,436
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	6,450,314	
9	(311) Structures and Improvements	286,146,089	2,232,512
10	(312) Boiler Plant Equipment	878,466,240	38,115,231
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	452,017,933	24,635,024
13	(315) Accessory Electric Equipment	159,829,889	1,049,529
14	(316) Misc. Power Plant Equipment	31,044,973	920,499
15	(317) Asset Retirement Costs for Steam Production	8,881,846	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,822,837,284	66,952,795
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	-150,918	
19	(321) Structures and Improvements	221,849,864	5,757,597
20	(322) Reactor Plant Equipment	260,987,209	10,157,634
21	(323) Turbogenerator Units	92,456,804	4,371,262
22	(324) Accessory Electric Equipment	179,293,785	1,552,158
23	(325) Misc. Power Plant Equipment	41,239,721	1,030,870
24	(326) Asset Retirement Costs for Nuclear Production	50,846	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	795,727,311	22,869,521
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	18,736,447	-2,191,584
38	(341) Structures and Improvements	115,685,661	55,584,470
39	(342) Fuel Holders, Products, and Accessories	78,838,575	32,929,520
40	(343) Prime Movers	778,606,966	328,666,120
41	(344) Generators	311,923,786	-51,946,605
42	(345) Accessory Electric Equipment	138,448,411	1,576,157
43	(346) Misc. Power Plant Equipment	18,183,402	1,176,524
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,460,423,248	365,794,602
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,078,987,843	455,616,918

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
			8,450,029		3
259,224	408,456		125,508,464		4
259,224	408,456		133,958,493		5
					6
					7
			6,450,314		8
1,085,816			287,292,785		9
16,933,960	-668,112		898,979,399		10
					11
9,547,063	-750,758		466,355,136		12
375,441	-9,272		160,494,705		13
180,524			31,784,948		14
			8,881,846		15
28,122,804	-1,428,142		1,860,239,133		16
					17
			-150,918		18
1,663,351	-267,152		225,676,958		19
2,075,107	-147,648		268,922,088		20
2,829,716	-110,158		93,888,192		21
221,912	-483,037		180,140,994		22
709,070	-161,093		41,400,428		23
			50,846		24
7,499,156	-1,169,088		809,928,588		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			16,544,863		37
3,749			171,266,382		38
758,644			111,009,451		39
84,879,971	-479,372		1,021,913,743		40
719,197			259,257,984		41
444,782			139,579,786		42
5,996			19,353,930		43
					44
86,812,339	-479,372		1,738,926,139		45
122,434,299	-3,076,602		4,409,093,860		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	12/31/2007	End of 2007/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	65,859,019	5,084,824
49	(352) Structures and Improvements	21,526,428	658,983
50	(353) Station Equipment	468,497,881	45,118,450
51	(354) Towers and Fixtures	66,465,751	41,974
52	(355) Poles and Fixtures	326,087,316	56,215,780
53	(356) Overhead Conductors and Devices	234,736,609	26,060,985
54	(357) Underground Conduit	7,010,980	
55	(358) Underground Conductors and Devices	9,598,587	12,679
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)	1,202,916,473	133,193,675
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	22,857,364	3,231,578
61	(361) Structures and Improvements	23,849,620	311,737
62	(362) Station Equipment	383,550,235	47,535,494
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	464,475,744	17,768,944
65	(365) Overhead Conductors and Devices	514,035,534	29,055,747
66	(366) Underground Conduit	193,259,133	11,544,265
67	(367) Underground Conductors and Devices	466,654,203	29,959,230
68	(368) Line Transformers	450,785,736	33,121,578
69	(369) Services	456,890,391	15,608,138
70	(370) Meters	113,069,617	4,545,980
71	(371) Installations on Customer Premises	2,222,150	159,899
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	275,236,771	14,657,843
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,366,886,498	207,500,433
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	10,704,306	
87	(390) Structures and Improvements	114,134,929	8,548,145
88	(391) Office Furniture and Equipment	10,365,657	3,335,947
89	(392) Transportation Equipment	144,235,965	3,915,634
90	(393) Stores Equipment	4,006,513	-50,059
91	(394) Tools, Shop and Garage Equipment	13,610,243	1,614,802
92	(395) Laboratory Equipment	3,114,385	129,949
93	(396) Power Operated Equipment	4,007,389	142,109
94	(397) Communication Equipment	59,416,292	13,283,326
95	(398) Miscellaneous Equipment	6,019,880	2,065,775
96	SUBTOTAL (Enter Total of lines 86 thru 95)	369,615,559	32,985,628
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)	371,589,798	32,985,628
100	TOTAL (Accounts 101 and 106)	9,151,036,437	832,450,090
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)	9,151,036,437	832,450,090

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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
			70,943,843		48
1,994			22,183,417		49
11,732,809	-1,632,488		500,251,034		50
5,484			66,502,241		51
3,421,280	38,390		378,920,206		52
2,082,905	52,030		258,766,719		53
			7,010,980		54
			9,611,266		55
			3,133,902		56
					57
17,244,472	-1,542,068		1,317,323,608		58
					59
			26,088,942		60
77,867			24,083,490		61
5,215,034	41,892		425,912,587		62
					63
1,562,924	-17,103		480,664,661		64
5,109,571	-1,251,675		536,730,035		65
124,022	-29,287		204,650,089		66
8,806,007	-9		487,807,417		67
6,212,878	-636,926		477,057,510		68
4,488,962	-3,399,558		464,610,009		69
110,246			117,505,351		70
	1,409		2,383,458		71
					72
2,601,854	-88,436		287,204,324		73
					74
34,309,365	-5,379,693		3,534,697,873		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
595,403			10,108,903		86
13,158,714			109,524,360		87
4,283,962	2,584,684		12,002,326		88
514,921			147,636,678		89
103,083			3,853,371		90
788,090			14,436,955		91
318,975			2,925,359		92
			4,149,498		93
8,161,366	308,345		64,846,597		94
334,017			7,751,638		95
28,258,531	2,893,029		377,235,685		96
					97
			1,974,239		98
28,258,531	2,893,029		379,209,924		99
202,505,891	-6,696,878		9,774,283,758		100
					101
					102
					103
202,505,891	-6,696,878		9,774,283,758		104

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	12/31/2007	End of 2007/Q4

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				
8	Other Land and Rights < $250K 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	7/90	12/2017	752,861
23				
24				
25				
26				
27				
28				
29				
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45				
46				
47	Total			35,089,957

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	12/31/2007	End of 2007/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	60BT0CRP0 BARTOW REPOWERING	387,957,291
2	60CR0CRP0 CRCA COMMON	109,853,258
3	6OLU1D STEAM GENERATOR MASTER	104,177,798
4	60CRN5CRP0 CR #5 FGD	75,191,945
5	60KK8-1910T1 BARTOW NE UG	57,128,000
6	60LG7D PURCHASE RAYONIER SITE	53,737,840
7	60CRN4CRP0 CR UNIT #4 FGD	53,686,859
8	60CRNCRP0 CR UNIT 4 SCR	46,342,164
9	60CRN5CRPO CR #5 SCR	41,625,206
10	60LU1D CR3 POWER UPRATE	38,052,484
11	60LG7 NNP COLA DEVLOP PEF	24,588,929
12	60KK8-1003T1 LBW REBUILD	10,777,042
13	60KK8-1777T1-CNTRL FL-BUSHNELL	9,125,371
14	60KK8D LAND - BASELOAD	8,941,425
15	60X00D-S38-PC'S 2008	8,617,136
16	60KK8-1650T1 NEW RIVER (WREC)	8,384,793
17	60KK8-1864S1 GINNIE NEW SUB	6,895,211
18	60CRN5CRP0 TURBINE PROJECT	6,338,850
19	60KK8-1721S1 BRONSON NEW SUB	6,260,211
20	60KK8-1070S1 DALLAS TRANSF	5,073,505
21	60KK8-1859S1 INTERCESSION CITY	4,437,023
22	60KK8-1910S1 BARTOW SUB TERM	4,352,516
23	60GB9D CR3 LICENSE RENEWAL MAS	4,230,506
24	60KK8-1788S2 ROSS PRAIRIE	4,200,032
25	60KK81124D1 SPRING LAKE TRANSF	3,438,955
26	60KK8-1650D1 ZEPHYRHILLS NORTH	3,396,250
27	60440D RUBY SUBST. LAND PURCH	2,838,431
28	60KK8-1777S4 BUSHNELL EAST	2,776,987
29	608981632T1 LK PLACID NO LINE	2,563,613
30	60KK8-1704T1-SILVER SPGS-SANTO	2,562,346
31	60KK8-1723T1 GROVELAND	2,401,572
32	60KK8D - TRM PEF BASELOAD STDY	2,395,153
33	608981632D2-LK PLACID N. SUB	2,306,101
34	CP HEC PB2A FALL CI-BOP	2,296,580
35	60034D 1850D1 CHAMP GATE	2,173,985
36	60KK8-1910S2 NORTHEAST SUB TER	2,159,889
37	60379D REDINGTON OH TO UG	2,147,715
38	60034D 1889D1 MARICAMP	2,049,990
39	60ANC9CRP4 COOLING TOWER 2	2,004,063
40	60KK8-1650S1 NEW RIVER SUB	1,975,277
41	60GB9D FP CODE CONF PROJECT	1,463,823
42	600341652D1-LAKE LUNTZ CAP	1,431,697
43	TOTAL	1,191,510,032

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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	VMS SOFTWARE	1,399,310
2	CRYSTAL RIVER IOH	1,377,354
3	60034D-1767D1 PINELLAS WATER	1,170,174
4	608961225D2 BEVILLES CORNER	1,098,516
5	CP HEC N-11B/N-11C RECLAMATION	1,042,095
6	60CR4CRP3 CR4 TURBINE PROJECT	1,030,093
7	60KK8-1003S1 LAKE BRYAN TERM	1,019,952
8		
9	Other Minor Projects	61,014,716
10		
11		
12		
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23		
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42		
43	TOTAL	1,191,510,032

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 216 Line No.: 1 Column: b

Increase over last year attributed to continued new generation construction at Bartow, licensing costs for new Nuclear generation, and an increased spending for Clean Air projects.

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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	4,287,022,870	4,287,022,870		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	286,866,834	286,866,834		
4	(403.1) Depreciation Expense for Asset Retirement Costs	354,972	354,972		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts	7,852,684	7,852,684		
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock - Oil and Rail Cars	2,377,867	2,377,867		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	297,452,357	297,452,357		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	202,505,891	202,505,891		
13	Cost of Removal	33,237,177	33,237,177		
14	Salvage (Credit)	71,470,644	71,470,644		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	164,272,424	164,272,424		
16	Other Debit or Cr. Items (Describe, details in footnote):	1,648,824	1,648,824		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,421,851,627	4,421,851,627		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,442,068,293	1,442,068,293		
21	Nuclear Production	585,845,278	585,845,278		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	515,001,082	515,001,082		
25	Transmission	467,787,323	467,787,323		
26	Distribution	1,314,366,808	1,314,366,808		
27	Regional Transmission and Market Operation				
28	General	96,782,843	96,782,843		
29	TOTAL (Enter Total of lines 20 thru 28)	4,421,851,627	4,421,851,627		

Schedule Page: 219 Line No.: 9 Column: c

Provision for Steam 312.0 Rail Cars	$1,697,695
Provision for Steam 311.0-315.0 & 316.3 Bartow-Anclote Pipeline	680,172
	$2,377,867

Schedule Page: 219 Line No.: 16 Column: c

Adjustments to Reserve:

Clearing Overhead	$ 388,975
Intercompany Reserve Transfers	1,050,561
Other Adjustments & Transfers	109,288
	$1,648,824

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)	239,606,898	245,349,474	Power Supply
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)	161,500,391	168,284,311	Various
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	20,750,479	24,765,470	Power Supply
8	Transmission Plant (Estimated)	1,071,828	1,528,817	Transmission
9	Distribution Plant (Estimated)	4,781,775	6,288,609	Customer Service
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	454,069	622,629	Various
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	188,558,542	201,489,836	
13	Merchandise (Account 155)	550,736	674,288	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)	5,825,542	33,546,843	Various
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	434,541,718	481,060,441	

Schedule Page: 227 Line No.: 12 Column: b

Account 154 Plant Materials and Operating Supplies includes an Inventory reserve account, credit balance of $1,829,771. During 2006, $2,835,278 was charged and $1,300,000 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 $5,084,386. Co-owned inventory accounts include Crystal River Unit 3 valued at $3,068,451 and Intercession City , Siemens Unit 11 valued at $2,015,935 at the end of 2006.

Schedule Page: 227 Line No.: 12 Column: c

Account 154 Plant Materials and Operating Supplies includes an Inventory reserve account, credit balance of $1,363,030. During 2007, $3,409,248 was charged and $2,942,507 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 $4,980,823. Co-owned inventory accounts include Crystal River Unit 3 valued at $3,169,075 and Intercession City, Siemens Unit 11 valued at $1,811,747 at the end of 2007.

Account 154 Plant Materials and Operating Supplies - Assigned to Other, represents inventory for Telecommunication and Corporate facilities that can not be readily assignable to a specific primary function.

Schedule Page: 227 Line No.: 16 Column: b

Account 163- Stores Expense Undistributed was charged with $4,086,670 and credited with $2,910,819 for a net charge of $1,175,851 during 2006. These charges to operations, maintenance and capital accounts were to record various inventory adjustments for 2006.

Schedule Page: 227 Line No.: 16 Column: c

Account 163 - Stores Expense Undistributed - Allocations accounts was charged with $2,970,161 and credited with $2,179,402 for a net charge of $790,758 during 2007. These charges to operations, maintenance and capital accounts were to record various inventory adjustments for 2007.

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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.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2008 No. (d)	2008 Amt. (e)
1	Balance-Beginning of Year	34,137.00	1,940,951	125,653.00	1,750
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	125,653.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Morgan Stanley, SO2	13,000.00	10,400,000		
10	Seasonal NOX				
11	Annual NOX				
12					
13					
14					
15	Total	13,000.00	10,400,000		
16					
17	Relinquished During Year:				
18	Charges to Account 509	131,093.00	9,437,260		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	41,697.00	2,903,691	125,653.00	1,750
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)		765,770		
45	Gains				
46	Losses				

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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.

2009 No. (f)	2009 Amt. (g)	2010 No. (h)	2010 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
125,653.00		119,141.00		2,384,731.00		2,789,315.00	1,942,701	1
[redacted]								2
								3
24,144.00		24,144.00		48,288.00		222,229.00		4
								5
[redacted]								6
								7
								8
						13,000.00	10,400,000	9
8,361.00	6,470,672					8,361.00	6,470,672	10
2,025.00	7,211,510	1,025.00	3,221,250	3,725.00	11,760,000	6,775.00	22,192,760	11
								12
								13
								14
10,386.00	13,682,182	1,025.00	3,221,250	3,725.00	11,760,000	28,136.00	39,063,432	15
[redacted]								16
								17
						131,093.00	9,437,260	18
[redacted]								19
								20
[redacted]								21
								22
								23
								24
								25
								26
								27
								28
160,183.00	13,682,182	144,310.00	3,221,250	2,436,744.00	11,760,000	2,908,587.00	31,568,873	29
[redacted]								30
								31
								32
								33
								34
								35
[redacted]								
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
[redacted]								41
								42
								43
					332,795		1,098,565	44
								45
								46

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FOOTNOTE DATA

Schedule Page: 228 Line No.: 4 Column: b

EPA issued SO2 allowances

Schedule Page: 228 Line No.: 4 Column: f

Represents EPA issued:

NOX Seasonal Allowances- 7,962
NOX Annual Allowances - 16,182

Schedule Page: 228 Line No.: 4 Column: h

Represents EPA issued:

NOX Seasonal Allowances- 7,962
NOX Annual Allowances - 16,182

Schedule Page: 228 Line No.: 4 Column: j

Represents EPA issued for 2011:

NOX Seasonal Allowances- 7,962
NOX Annual Allowances - 16,182

Represents EPA issued for 2012:

NOX Seasonal Allowances- 7,962
NOX Annual Allowances - 16,182

PGN Allowance allocations for seasonal and annual NOX, beyond 2012, have not yet been populated to PGN EPA accounts.

Schedule Page: 228 Line No.: 10 Column: a

Seasonal NOX Purchases

Koch	545
Duke	150
Koch	500
Constellation	2000
Constellation	193
Louis Dreyfus	17
Duke	200
Evolution	90
Univ Michigan	32
Exelon	350
VPEM	250
NRG	500
NRG	200
AEP	300
Koch	650
Midland MCV	111
DTE	200
St Lawrence	100
Sempra	100
AES	100
Mittal	271
AEP	100
Domtar	52
Constellation	300
Koch	250

Constellation	300
Constellation	300
St Lawrence	100
Intl Paper	100
Total	8361

Schedule Page: 228 Line No.: 11 Column: a

Annual NOX Allowance Purchases

Koch	3900
LSP	1875
Whitewater	
Koch	200
Contstellation	100
Contstellation	200
Louis Dreyfus	100
AECI	100
AECI	300
Total	6775

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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.)	16,963,061		4073701	434,000	15,658,702
6						
7	Storm Extraordinary Property Loss					
8	Retail (FPSC Order No. PSC-05-					
9	0748-FOF-EI Docket No. 041272-EI					
10	amortization over two years.)	240,759,265		4070003	73,892,516	
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL	257,722,326			74,326,516	15,658,702

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Proposed Nuclear Units				
3	Levy County, FL:				
4	Impact Study Phase 2	99,058	561.6		
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Proposed Nuclear Units				
23	Levy County, FL:				
24	a. Impact Study Phase 1	200,000	561.7		
25	b. Impact Study Phase 2	86,000	561.7		
26	c. COLA Study	90,000	561.7		
27	d. Resource Need Study	44,052	561.7		
28					
29	Progress Energy Florida, FMPA, and				
30	SEC Cooperative Interconnection				
31	Studies	25,260	561.7		
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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 $50,000 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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Accumulated Deferred Taxes - FAS 109	110,299,000	18,095,000			128,394,000
2	Period of Amortization occurs					
3	as temporary differences occur.					
4						
5	Nuclear Decom/Decontamination	60,593		5188200	60,593	
6	Amortization Period = 12 months					
7						
8	Load Control Switches - Investment	3,690,536	4,062,357	1861902	1,135,856	6,617,037
9	Load Control Switches - Amortization	(1,429,427)	356,718	9080120	1,005,481	-2,078,190
10						
11	Deferred Energy Conservation Expense	(11,561,098)	18,589,301	9080110	7,028,203	
12						
13	Sebring Transition Rider	5,476,623	18,707	1861904	3,600,005	1,895,325
14	Sebring - Over(Under) Recovered	(1,539,653)	3,846,794	4044002	3,428,111	-1,120,970
15						
16	Interest on Tax Deficiency	(1,773,696)	13,534,824	4310024	12,389,558	-628,430
17						
18	Deferred GPIF Asset		607,201			607,201
19	Deferred Fuel Expense - Full Req	3,761,204	7,314,478	5572002	4,736,837	6,338,845
20	Deferred Fuel Expense - Prior Year	385,055		5572002	385,055	
21	Deferred Capacity Expense - Prior Year	8,762,537		5572001	5,380,565	3,381,972
22	Deferred Capacity Expense - Current Year		31,045,256	5572001	21,808,592	9,236,664
23						
24	Deferred Environmental Cost Recovery	14,561,102		9350003	14,561,102	
25	Accrued Environmental Cost Recovery	42,512,581	9,001,412	2284800	21,664,846	29,849,147
26						
27	Florida Minimum Pension Liability	130,165,119	763,875	2283151-70	45,421,601	85,507,393
28						
29	Regulatory Asset Derivative MTM Oil	78,069,987	102,889,441	2543015-7	180,959,428	
30						
31	Regulatory Asset - FAS 143 Asbestos	213,003	26,739			239,742
32						
33	Rate Case Expense	923,200		4073702	923,200	
34						
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43						
44	TOTAL	382,576,666	210,152,103		324,489,033	268,239,736

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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 $50,000, 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	-44,041	12,421,294		12,116,459	260,794
2	Southern Company Capacity	803,433				803,433
3	NFPP Generation Study	26,763	76,033	Various	21,318	81,478
4	Longwood Hydrogen Vehicle	50,672				50,672
5	Hurricane Alberto	1,043,941	218,210	Various	1,262,151	
6	Hurricane Ernesto	1,039,780	44,260	Various	1,084,040	
7	Vacation Pay Accrual	4,982,732	5,959,012	242	4,982,732	5,959,012
8	Labor Accrual	1,506,438	40,049,095	242	39,647,799	1,907,734
9	February 2007 Tornado		2,984,742	Various	2,984,742	
10	Topaz Energy		1,077,000	Various	1,077,000	
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	9,409,718				9,063,123

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	35,630,000	41,489,000
3	LIFE/MEDICAL BENEFITS	97,365,000	111,652,000
4	UNAMORTIZED INVESTMENT TAX CREDIT	9,060,000	6,730,000
5	REGULATORY LIABILITY	17,845,000	14,958,000
6	NUCLEAR DECOMMISSIONING	99,579,000	102,076,000
7	OTHER	120,767,000	181,629,900
8	TOTAL Electric (Enter Total of lines 2 thru 7)	380,246,000	458,534,900
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)	380,246,000	458,534,900

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	12/31/2007	End of 2007/Q4

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
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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)	
100	354,405,315					1
100	354,405,315					2
						3
39,980	3,998,000					4
39,997	3,999,700					5
80,000	8,000,000					6
75,000	7,500,000					7
99,990	9,999,000					8
						9
						10
334,967	33,496,700					11
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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	12/31/2007	End of 2007/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	739,992,013
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)	7,906,683
27	Misc PIC - Restricted Stock Units (RSU)	3,687,449
28		
29		
30		
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39		
40	TOTAL	754,871,665

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 - 6-7/8%	80,000,000	765,503
4			1,069,599 D
5	First Mortgage Bonds - 4.8%	425,000,000	4,585,299
6			1,513,000 D
7	First Mortgage Bonds - 5.9%	225,000,000	3,013,280
8			571,500 D
9	First Mortgage Bonds - 5.1%	300,000,000	3,473,110
10			594,000 D
11	First Mortgage Bonds - 4.5%	300,000,000	3,291,598
12			2,115,000 D
13	Medium Term Note (Sebring) - 6.67%	30,700,000	280,604
14			
15	Medium Term Note - 6.81%	85,000,000	534,680
16			
17	Medium Term Note - 6.75%	150,000,000	5,528,498
18			436,500 D
19	Series A Senior Note - Floating Rate	450,000,000	1,555,087
20			1,575,000 D
21	Pollution Control Bonds (Citrus) 2002A	108,550,000	2,356,705
22			
23	Pollution Control Bonds (Citrus) 2002B	100,115,000	2,081,983
24			
25	Pollution Control Bonds (Citrus) 2002C	32,200,000	756,175
26			
27	RCA - 5 Year		1,009,474
28			
29	First Mortgage Bonds - 6.35%	500,000,000	6,599,534
30			660,000 D
31	First Mortgage Bonds - 5.80%	250,000,000	2,853,445
32			672,500 D
33	TOTAL	3,336,565,000	51,503,731

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/Q4

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.
7/18/01	7/15/11	7/18/01	7/15/11	300,000,000	19,950,000	1
						2
2/09/93	2/01/08	2/09/93	2/01/08	80,000,000	5,500,000	3
						4
2/21/03	3/1/13	2/21/03	3/1/13	425,000,000	20,400,000	5
						6
2/21/03	2/15/33	2/21/03	2/15/33	225,000,000	13,275,000	7
						8
11/21/03	12/1/15	11/21/03	12/1/15	300,000,000	15,300,000	9
						10
5/16/05	6/1/10	5/16/05	6/1/10	300,000,000	13,500,000	11
						12
4/20/93	4/1/08	4/20/93	4/1/08	1,900,002	246,789	13
						14
7/25/97	7/1/07	7/25/97	7/1/07		2,894,250	15
						16
2/13/98	2/1/28	2/13/98	2/1/28	150,000,000	10,125,000	17
						18
12/13/05	11/14/08	12/13/05	11/14/08	450,000,000	26,241,159	19
						20
8/13/02	1/01/27	8/13/02	1/01/27	108,550,000	3,969,915	21
						22
8/20/02	1/01/22	8/20/02	1/01/22	100,115,000	3,701,010	23
						24
7/24/02	1/01/18	7/24/02	1/01/18	32,200,000	1,173,717	25
						26
3/28/05	3/28/10	3/28/05	3/28/10			27
						28
9/12/07	9/15/37	9/12/07	9/15/37	500,000,000	9,906,956	29
						30
9/12/07	9/15/17	9/12/07	9/15/17	250,000,000	4,495,026	31
						32
				3,222,765,002	150,678,822	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)	317,330,866
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	121,023,665
11		
12	Deductions Recorded on Books Not Deducted for Return	1,354,240,285
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	-1,331,506,216
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	461,088,600
28	Show Computation of Tax:	
29	Provision for Federal Income Tax at 35%	161,381,010
30	True up Entries and Other Tax Benefits	-1,609,487
31	Total Federal Income Tax Provision (409120F - 409220F) True up Entries	159,771,523
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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) 12/31/2007	Year/Period of Report End of 2007/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	-54,054,730		159,771,523	144,970,313	
3	FICA	660,233		22,667,686	23,317,038	
4	Unemployment	5,125		260,482	249,896	
5	Special Fuel Tax					
6	Excise Tax					
7	Highway Use					
8	Payroll Tax	1,487,828			-347,556	
9	SUBTOTAL	-51,901,544		182,699,691	168,189,691	
10						
11	STATE TAXES					
12	Income	6,609,169		28,599,820	34,608,169	
13	Income Tax Subsidiary					
14	Gross Receipts	15,098,945		102,285,395	110,483,496	
15	Unemployment	34,363		1,038,335	1,010,949	
16	Intangibles			8,908	8,908	
17	Regulatory Assessment	1,593,822		3,000,529	2,906,499	
18	Sales Tax-Company Use	12,827		181,755	179,037	
19	SUBTOTAL	23,349,126		135,114,742	149,197,058	
20						
21	COUNTY & LOCAL TAXES					
22	Property-County & Local			85,047,451	85,047,451	
23	FL Privilege License			8,921	8,921	
24	Franchise-Local	7,019,931		97,653,213	98,041,380	
25						
26						
27	Adj-Use Tax on Purchases					
28	SUBTOTAL	7,019,931		182,709,585	183,097,752	
29						
30						
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41	TOTAL	-21,532,487		500,524,018	500,484,501	

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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
-39,253,520		155,587,614			4,183,909	2
10,881		20,840,315			1,827,371	3
15,710					260,482	4
						5
						6
						7
1,835,384						8
-37,391,545		176,427,929			6,271,762	9
						10
						11
600,820		28,773,090			-173,270	12
						13
6,900,844		102,285,395				14
61,749					1,038,335	15
		8,908				16
1,687,852		3,000,529				17
15,545		181,755				18
9,266,810		134,249,677			865,065	19
						20
						21
		84,943,684			103,766	22
		8,921				23
6,631,764		97,653,213				24
						25
						26
						27
6,631,764		182,605,818			103,766	28
						29
						30
						31
						32
						33
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						39
						40
-21,492,971		493,283,424			7,240,593	41

Schedule Page: 262 Line No.: 27 Column: b

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.

	Balance at Beginning of Year	Balance at End of Year
Taxes Accrued, P. 112, line 37	(21,326,851)	(21,197,682)
State Sales Tax on Purchases	(200,871)	(289,398)
County Sales Tax on Purchases	(4,764)	(5,891)
	(21,532,487)	(21,492,971)

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	23,386,508			4114001	5,940,000	
6							
7							
8	TOTAL	23,386,508				5,940,000	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
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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) 12/31/2007	Year/Period of Report End of 2007/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
17,446,508	27 years		5
			6
			7
17,446,508			8
			9
			10
			11
			12
			13
			14
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			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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 $10,000, 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	FAS 146 Deferred Exit Costs	781,961	131	619,209	77,522	240,274
2	Wholesale Deposits - SECI	7,130,000	131	320,000		6,810,000
3	Wholesale Deposits - Mirant	6,000,000	131	6,000,000		
4	Wholesale Deposits - Other	232,942	253	54,483	60,000	238,459
5	Wholesale Deposits - FMPA	1,320,000	131	20,000		1,300,000
6	Interest on Tax Deficiency		various	557,745	15,114,961	14,557,216
7	Cable and Other Deposits	538,861	131, 242	2,445,713	2,935,370	1,028,518
8	Deferred Rent Expenses	312,206	242, 931	256,871	506,604	561,939
9	Franchise Settlements	1,838,000	131	254,000		1,584,000
10	PEP Lease Incentives	275,252	242	763,880	4,203,845	3,715,217
11	PTC Fiber 400 Indemnification	7,824,127	242	236,542	65,539	7,653,124
12	Joint Owner	281,349	various	11,449,679	10,662,576	-505,754
13	Various	103,993	various	5,714,831	5,709,612	98,774
14						
15						
16						
17						
18						
19						
20						
21						
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43						
44						
45						
46						
47	TOTAL	26,638,691		28,692,953	39,336,029	37,281,767

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	6,186,000		
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	6,186,000		
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)	6,186,000		
18	Classification of TOTAL			
19	Federal Income Tax	5,304,000		
20	State Income Tax	882,000		
21	Local Income Tax			

NOTES

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/Q4

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
						6,186,000	4
							5
							6
							7
						6,186,000	8
							9
							10
							11
							12
							13
							14
							15
							16
						6,186,000	17
							18
						5,304,000	19
						882,000	20
							21

NOTES (Continued)

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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	440,451,000	61,742,000	60,860,000
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	440,451,000	61,742,000	60,860,000
6	Other			
7	Other			
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	440,451,000	61,742,000	60,860,000
10	Classification of TOTAL			
11	Federal Income Tax	378,354,000	52,920,000	52,183,000
12	State Income Tax	62,097,000	8,822,000	8,677,000
13	Local Income Tax			

NOTES

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.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
	240,000					441,093,000	2
							3
							4
	240,000					441,093,000	5
							6
							7
							8
	240,000					441,093,000	9
							10
	205,000					378,886,000	11
	35,000					62,207,000	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	42,540,000	6,981,000	
4				
5				
6				
7				
8	Other	270,902,909	106,065,470	63,176,235
9	TOTAL Electric (Total of lines 3 thru 8)	313,442,909	113,046,470	63,176,235
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)	313,442,909	113,046,470	63,176,235
20	Classification of TOTAL			
21	Federal Income Tax	268,869,842	96,480,296	52,583,377
22	State Income Tax	44,573,067	16,566,174	10,592,858
23	Local Income Tax			

NOTES

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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				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
						49,521,000	3
							4
							5
							6
							7
622,339		Various	63,814,718	Various	70,051,778	320,651,543	8
622,339			63,814,718		70,051,778	370,172,543	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
622,339			63,814,718		70,051,778	370,172,543	19
							20
			55,326,816		60,444,623	317,884,568	21
622,339			8,487,902		9,607,155	52,287,975	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: g

Adjustments to 283 - Various Accounts

Debits to 283 - Credits to Various Accounts		Credits to 283 - Debits to Various Accounts	
2163001	(187,149)	19011FE	11,870,000
23612FE	(308,290)	19011FL	1,974,000
23612FL	(51,265)	28311FE	48,574,623
28315FE	(48,574,623)	28311FL	7,633,155
28315ST	(7,633,155)		
19010FE	(893,000)		
19010FL	(149,000)		
19011FE	(2,030,000)		
19011FL	(338,000)		
409220J	(59,816)		
23615FE	(1,463,522)		
23615ST	(229,982)		
409120F	(1,896,916)		
Total Credits	(63,814,718)	Total Debits	70,051,778

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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 $50,000 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	46,261,516	4111000	7,485,000		38,776,516
2	Period of Amortization occurs as					
3	temporary differences occur.					
4						
5	Regulatory Liability Fuel				14,181,482	14,181,482
6	Deferred Fuel Revenue - Current Year		5572002	50,564,615	174,269,517	123,704,902
7	Deferred Fuel Revenue - Prior Year	75,729,927	5572002	78,357,964	31,492,651	28,864,614
8	Deferred GPIF Liability	1,547,048	4560096	1,547,048		
9						
10	Deferred Environmental Cost Recovery		9350003		4,667,390	4,667,390
11						
12	ARO - Nuclear Decom Trust Unrl Gains	158,828,143	1289191	44,428,924	48,216,197	162,615,416
13	ARO - SFAS 143 Nuclear Decom	84,512,275	4073002	14,718,872	25,178,266	94,971,669
14	ARO - SFAS 143 Asbestos	3,211,990	4073002	1,806,615		1,405,375
15						
16	Auctioned S02 Allowance	6,115,691	4074004	5,194,317	1,098,566	2,019,940
17						
18	Winter Park Stranded Costs - 6/05-12/10	4,480,976	4560001	1,506,000		2,974,976
19						
20	Regulatory Llability Derivative MTM Oil		1823015	215,968,089	382,044,056	166,075,967
21						
22	Deferred Energy Conservation				14,173,795	14,173,795
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	380,687,566		421,577,444	695,321,920	654,432,042

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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.

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	2,363,141,608	2,360,716,289
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,153,050,552	1,151,511,214
5	Large (or Ind.) (See Instr. 4)	317,415,092	345,703,073
6	(444) Public Street and Highway Lighting	1,892,499	2,002,621
7	(445) Other Sales to Public Authorities	302,878,128	299,096,915
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,138,377,879	4,159,030,112
11	(447) Sales for Resale	435,681,011	321,091,934
12	TOTAL Sales of Electricity	4,574,058,890	4,480,122,046
13	(Less) (449.1) Provision for Rate Refunds	1,675,074	898,573
14	TOTAL Revenues Net of Prov. for Refunds	4,572,383,816	4,479,223,473
15	Other Operating Revenues		
16	(450) Forfeited Discounts	23,058,391	22,682,285
17	(451) Miscellaneous Service Revenues	25,044,986	27,106,754
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	79,006,174	73,410,503
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-6,970,035	-42,516,287
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	120,139,516	80,683,255
27	TOTAL Electric Operating Revenues	4,692,523,332	4,559,906,728

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ELECTRIC OPERATING REVENUES (Account 400)

5. 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.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. 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
19,911,884	20,020,717	1,442,854	1,431,742	2
				3
12,183,637	11,975,026	162,837	162,774	4
3,819,403	4,160,024	2,668	2,697	5
26,102	26,650	1,692	1,748	6
3,340,612	3,249,420	22,379	21,412	7
				8
				9
39,281,638	39,431,837	1,632,430	1,620,373	10
5,930,039	4,532,942	21	23	11
45,211,677	43,964,779	1,632,451	1,620,396	12
				13
45,211,677	43,964,779	1,632,451	1,620,396	14

Line 12, column (b) includes $ 0 of unbilled revenues.
Line 12, column (d) includes 0 MWH relating to unbilled revenues

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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 Service	19,911,884	2,363,141,608	1,442,854	13,800	0.1187
2						
3	Commercial and Industrial Service	16,003,040	1,470,465,644	165,505	96,692	0.0919
4						
5	Public Street and Highway	26,102	1,892,499	1,692	15,427	0.0725
6	Lighting					
7						
8	Other Sales to Public	3,340,612	302,878,128	22,379	149,274	0.0907
9	Authorities					
10						
11	Total Sales to Ultimate	39,281,638	4,138,377,879	1,632,430	24,063	0.1054
12						
13						
14						
15						
16						
17						
18						
19						
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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	12/31/2007	End of 2007/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	REQUIREMENT SERVICE					
2	CITY OF BARTOW	RQ	TARIFF NO. 9	55	55	55
3	CITY OF CHATTAHOOCHEE	RQ	FERC NO. 126	6	6	6
4	CITY OF HOMESTEAD	RQ	TARIFF NO. 9	30	30	30
5	CITY OF KISSIMMEE	RQ	FERC NO. 120	0	0	0
6	CITY OF MOUNT DORA	RQ	FERC NO. 127	20	20	20
7	CITY OF NEW SMYRNA BEACH	RQ	FERC NO. 144	15	15	15
8	CITY OF QUINCY	RQ	TARIFF NO. 1	20	20	20
9	CITY OF ST CLOUD	RQ	FERC NO. 121	0	0	0
10	CITY OF TALLAHASSEE	RQ	FERC NO. 178	11	11	11
11	CITY OF WILLISTON	RQ	FERC NO. 124	7	7	7
12	CITY OF WINTER PARK	RQ	FERC NO. 191	82	82	82
13	FLORIDA MUNICIPAL POWER AGENCY	RQ	FERC NO. 107	35	32	32
14	FLORIDA POWER AND LIGHT	RQ	TARIFF No. 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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,line 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.
					1
304,113	6,314,014	14,386,016	18,720	20,718,750	2
33,202	664,696	1,618,905	3,168	2,286,769	3
210,640	3,785,000	9,994,290		13,779,290	4
			8,004	8,004	5
102,377	2,172,339	5,457,210	264	7,629,813	6
99,488	1,869,000	4,777,967	996	6,647,963	7
115,462	2,271,326	5,617,039	6,336	7,894,701	8
			996	996	9
99,877	-163,202	4,194,834		4,031,632	10
36,009	771,125	1,781,176	3,168	2,555,469	11
457,219	8,179,246	25,067,300		33,246,546	12
130,262	3,942,974	6,569,831	71,040	10,583,845	13
					14
5,594,789	113,994,012	303,354,344	1,034,176	418,382,532	
335,250	0	17,854,558	-556,079	17,298,479	
5,930,039	**113,994,012**	**321,208,902**	**478,097**	**435,681,011**	

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	12/31/2007	End of 2007/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)	Average Monthly CP Demand (f)
1	REEDY CREEK IMPROVEMENT DISTRICT	RQ	FERC NO. 118	95	95	95
2	SEMINOLE ELECTRIC COOPERATIVE, INC	RQ	FERC NO. 106	752	793	752
3	SOUTHEASTERN POWER ADMIN	RQ	FERC NO. 65	12	12	9
4	TAMPA ELECTRIC COMPANY	RQ	FERC NO. 7	69	69	69
5						
6						
7						
8	NON-REQUIREMENTS SERVICE					
9	ALABAMA ELECTRIC CO-OP	OS	FERC NO. 148			
10	CONOCO PHILLIPS	OS	FERC NO.10			
11	COBB ELECTRIC MEMBERSHIP CORP	OS	FERC NO. 10			
12	CARGILL-ALLIANT	OS	FERC NO. 8			
13	DTE ENERGY TRADING	OS	FERC NO. 176			
14	DUKE POWER COMPANY	OS	FERC NO. 10			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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.
771,689	14,157,530	28,796,055	33,984	42,987,569	1
2,632,433	55,042,893	172,110,969	887,500	228,041,362	2
53,668	372,063	2,489,542		2,861,605	3
548,350	14,615,008	20,493,210		35,108,218	4
					5
					6
					7
					8
2,400		83,479		83,479	9
67		8,136		8,136	10
55,326		2,790,953		2,790,953	11
10,841		610,246		610,246	12
					13
					14
5,594,789	113,994,012	303,354,344	1,034,176	418,382,532	
335,250	0	17,854,558	-556,079	17,298,479	
5,930,039	**113,994,012**	**321,208,902**	**478,097**	**435,681,011**	

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	12/31/2007	End of 2007/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 Classification	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	FLORIDA MUNICIPAL POWER AGENCY	OS	FERC NO. 105			
2	FLORIDA POWER & LIGHT CO	OS	FERC NO. 81/02			
3	GAINESVILLE REGIONAL UTILITIES	OS	FERC NO. 88			
4	HOMESTEAD, CITY OF	OS	FERC NO. 82			
5	LAKELAND, CITY OF	OS	FERC NO 92			
6	NEW SMYRNA BEACH, CITY OF (1)	OS	FERC NO. 104			
7	OGLETHORPE	OS	FERC NO. 139			
8	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86			
9	PJM INTERCONNECTION, LLC	OS	PJM			
10	REEDY CREEK UTILITIES	OS	FERC NO. 119			
11	SOUTH CAROLINA ELEC & GAS CO	OS	FERC NO. 8/10			
12	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128			
13	SOUTHERN COMPANY SERVICES	OS	FERC NO. 111			
14	TALLAHASSEE, CITY OF (1)	OS	FERC NO. 122			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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.
4,812		291,989		291,989	1
2,830		117,223		117,223	2
					3
					4
350		76,593		76,593	5
1,780		308,789	-50,883	257,906	6
1,360		64,838		64,838	7
10,005		378,914		378,914	8
35,905		1,935,302		1,935,302	9
6,425		241,163		241,163	10
					11
47,359		2,764,264		2,764,264	12
5,200		313,947		313,947	13
459		534,040	-505,196	28,844	14
5,594,789	113,994,012	303,354,344	1,034,176	418,382,532	
335,250	0	17,854,558	-556,079	17,298,479	
5,930,039	**113,994,012**	**321,208,902**	**478,097**	**435,681,011**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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 long-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.
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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	THE ENERGY AUTHORITY	OS	FERC NO. 175			
2	TAMPA ELECTRIC CO	OS	FERC NO. 80			
3	TENNESSEE VALLEY AUTHORITY	OS	FERC NO. 138			
4	MORGAN STANLEY	OS	FERC NO. 177			
5	CONSTELLATION ENERGY COMMODITIES	OS	FERC No. 8			
6	AMERICAN ELECTRIC POWER SERVICE	OS	FERC No. 8			
7						
8						
9						
10						
11						
12						
13						
14						
	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	12/31/2007	End of 2007/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,line 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.
15,135		841,093		841,093	1
113,970		5,419,809		5,419,809	2
18,998		979,220		979,220	3
					4
1,928		88,564		88,564	5
100		5,996		5,996	6
					7
					8
					9
					10
					11
					12
					13
					14
5,594,789	113,994,012	303,354,344	1,034,176	418,382,532	
335,250	0	17,854,558	-556,079	17,298,479	
5,930,039	113,994,012	321,208,902	478,097	435,681,011	

Schedule Page: 310.1 Line No.: 8 Column: a

Non-requirement Service is either:

(1) Economy Interchanges Sales for
pages 310.1 lines 9-14,
pages 310.2 lines 1-14,
pages 310.3 lines 1-5 and 7-9

(2) Economy and Emergency Sales for
pages 310.3 line 6

Schedule Page: 310.2 Line No.: 6 Column: a

2007 OS Sales for New Smyrna Beach includes ($50,883)capacity credit.

Schedule Page: 310.2 Line No.: 14 Column: a

2007 OS Sales for Tallahassee, City of includes ($505,192) capacity credit

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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	1,398,411	1,440,326
5	(501) Fuel	919,875,212	791,379,344
6	(502) Steam Expenses	6,951,033	7,498,258
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,887	40,992
10	(506) Miscellaneous Steam Power Expenses	25,563,301	20,285,051
11	(507) Rents		
12	(509) Allowances	9,437,260	7,670,904
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	963,227,104	828,314,875
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,930,908	2,557,945
16	(511) Maintenance of Structures	2,017,648	1,489,049
17	(512) Maintenance of Boiler Plant	10,900,717	9,997,882
18	(513) Maintenance of Electric Plant	3,106,253	4,269,282
19	(514) Maintenance of Miscellaneous Steam Plant	32,336,081	28,283,004
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	50,291,607	46,597,162
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,013,518,711	874,912,037
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	1,231,265	1,322,590
25	(518) Fuel	30,323,189	32,895,863
26	(519) Coolants and Water	3,634,057	3,739,552
27	(520) Steam Expenses	10,829,485	9,518,971
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	8,254	12,876
31	(524) Miscellaneous Nuclear Power Expenses	39,128,068	35,245,095
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	85,154,318	82,734,947
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	9,826,499	8,268,728
36	(529) Maintenance of Structures	1,537,159	6,328,529
37	(530) Maintenance of Reactor Plant Equipment	17,510,007	17,243,751
38	(531) Maintenance of Electric Plant	2,650,445	-2,416,100
39	(532) Maintenance of Miscellaneous Nuclear Plant	2,619,148	1,886,813
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	34,143,258	31,311,721
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	119,297,576	114,046,668
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	12/31/2007	End of 2007/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	7,703,260	8,190,817
63	(547) Fuel	746,008,168	620,689,433
64	(548) Generation Expenses	5,281,861	4,996,344
65	(549) Miscellaneous Other Power Generation Expenses	7,592,687	6,526,498
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	766,585,976	640,403,092
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	527,851	722,439
70	(552) Maintenance of Structures	88,862	143,890
71	(553) Maintenance of Generating and Electric Plant	2,127,618	2,811,679
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	18,830,624	11,830,952
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	21,574,955	15,508,960
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	788,160,931	655,912,052
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	885,492,819	762,324,823
77	(556) System Control and Load Dispatching	3,342,542	3,883,931
78	(557) Other Expenses	40,970	22,337
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	888,876,331	766,231,091
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,809,853,549	2,411,101,848
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,573,682	1,968,427
84	(561) Load Dispatching	196,591	923,610
85	(561.1) Load Dispatch-Reliability	1,071,319	594,292
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	617,624	490,241
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,227,897	925,994
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	508,073	420,413
90	(561.6) Transmission Service Studies	105,598	61,018
91	(561.7) Generation Interconnection Studies	560,792	36,541
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	116,785	303,199
94	(563) Overhead Lines Expenses	36,856	485,230
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	15,710,347	15,839,800
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	21,725,564	22,048,765
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	43,846	28,892
104	(569.2) Maintenance of Computer Software	137,395	72,347
105	(569.3) Maintenance of Communication Equipment	49,163	28,893
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	4,565,315	2,900,120
108	(571) Maintenance of Overhead Lines	7,040,485	7,071,529
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	2,467,252	4,224,614
111	TOTAL Maintenance (Total of lines 101 thru 110)	14,303,456	14,326,395
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	36,029,020	36,375,160

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	12/31/2007	End of 2007/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	10,352,589	8,708,268
135	(581) Load Dispatching	4,018,262	3,998,893
136	(582) Station Expenses	60,454	496,843
137	(583) Overhead Line Expenses	5,497,932	1,413,089
138	(584) Underground Line Expenses	3,266,204	-116,945
139	(585) Street Lighting and Signal System Expenses	4,513,562	3,746,958
140	(586) Meter Expenses	9,031,904	7,327,345
141	(587) Customer Installations Expenses	983,562	431,209
142	(588) Miscellaneous Expenses	39,163,804	37,012,597
143	(589) Rents	573,150	3,329,469
144	TOTAL Operation (Enter Total of lines 134 thru 143)	77,461,423	66,347,726
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,523,003	2,208,935
147	(591) Maintenance of Structures	13,567	131,795
148	(592) Maintenance of Station Equipment	3,483,217	2,575,087
149	(593) Maintenance of Overhead Lines	30,541,293	31,190,330
150	(594) Maintenance of Underground Lines	8,882,118	9,869,250
151	(595) Maintenance of Line Transformers	417,439	555,542
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters	470,773	823,927
154	(598) Maintenance of Miscellaneous Distribution Plant	21,405,981	15,947,716
155	TOTAL Maintenance (Total of lines 146 thru 154)	67,737,391	63,302,582
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	145,198,814	129,650,308
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,349,756	1,300,976
160	(902) Meter Reading Expenses	2,792,307	5,393,606
161	(903) Customer Records and Collection Expenses	28,000,223	26,074,571
162	(904) Uncollectible Accounts	14,312,525	13,114,059
163	(905) Miscellaneous Customer Accounts Expenses	4,594,186	4,472,786
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	51,048,997	50,355,998

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	12/31/2007	End of 2007/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	851,920	870,292
168	(908) Customer Assistance Expenses	63,229,204	60,070,737
169	(909) Informational and Instructional Expenses	8,025,594	3,733,319
170	(910) Miscellaneous Customer Service and Informational Expenses	191,013	33,003
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	72,297,731	64,707,351
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,690,130	1,819,546
176	(913) Advertising Expenses		1,566
177	(916) Miscellaneous Sales Expenses	273,910	542,791
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,964,040	2,363,903
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	57,011,640	50,064,147
182	(921) Office Supplies and Expenses	31,319,666	37,970,774
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	34,341,216	35,260,718
185	(924) Property Insurance	56,253,594	10,256,730
186	(925) Injuries and Damages	13,570,940	6,124,390
187	(926) Employee Pensions and Benefits	57,607,185	45,456,955
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	290,638	160,314
190	(929) (Less) Duplicate Charges-Cr.	924,167	749,146
191	(930.1) General Advertising Expenses	550,155	1,402,110
192	(930.2) Miscellaneous General Expenses	9,679,913	2,020,834
193	(931) Rents	9,988,759	6,880,813
194	TOTAL Operation (Enter Total of lines 181 thru 193)	269,689,539	194,848,639
195	Maintenance		
196	(935) Maintenance of General Plant	23,279,541	-4,587,787
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	292,969,080	190,260,852
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,409,361,231	2,884,815,420

Schedule Page: 320 Line No.: 185 Column: b

Property insurance includes $46,625,557 of recoveries from the retail jurisdiction to fund the self-insured retail storm reserve.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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	PURCHASED POWER:					
2	SOUTHEASTERN POWER ADM	OS	FERC NO. 65	N/A	N/A	N/A
3	GLADES ELECTRIC COOPERATIVE INC.	OS	*	N/A	N/A	N/A
4	AUBURNDALE POWER PARTNERS (1)	OS	COG	136	157	154
5	AUBURNDALE POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
6	BAY COUNTY(1)	OS	COG	0	0	0
7	BAY COUNTY (1)	AD	COG	N/A	N/A	N/A
8	CARGILL FERTILIZER (1)	OS	COG	13	41	12
9	CARGILL FERTILIZER (1)	AD	COG	N/A	N/A	N/A
10	CITRUS WORLD (1)	OS	COG	N/A	0	0
11	CITRUS WORLD (1)	AD	COG	N/A	N/A	N/A
12	JEFFERSON POWER L.C. (1)	OS	COG	N/A	N/A	N/A
13	JEFFERSON POWER L.C. (1)	AD	COG	N/A	N/A	N/A
14	LAKE COUNTY (1)	OS	COG	11	13	10
	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	12/31/2007	End of 2007/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		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
16,620				811,020		811,020	2
171				18,041		18,041	3
652,994			38,997,221	26,719,809		65,717,030	4
					37,868	37,868	5
360				13,830		13,830	6
					-895	-895	7
51,773			6,500,159	949,258		7,449,417	8
					-41,352	-41,352	9
53				2,462		2,462	10
23					953	953	11
							12
							13
88,884			6,412,230	2,325,433		8,737,663	14
11,048,123			408,693,387	477,859,997	-1,060,565	885,492,819	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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	LAKE COUNTY (1)	AD	COG	N/A	N/A	N/A
2	LAKE COGEN LIMITED (1)	OS	COG	102	111	106
3	LAKE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
4	DADE COUNTY (1)	OS	COG	35	49	34
5	DADE COUNTY (1)	AD	COG	N/A	N/A	N/A
6	ORANGE COGEN LIMITED (1)	OS	COG	71	101	82
7	ORANGE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
8	ORLANDO COGEN LIMITED (1)	OS	COG	78	125	109
9	ORLANDO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
10	PASCO COGEN LIMITED (1)	OS	COG	111	122	101
11	PASCO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
12	PASCO COUNTY (1)	OS	COG	22	26	20
13	PASCO COUNTY (1)	AD	COG	N/A	N/A	N/A
14	PCS PHOSPHATE (1)	OS	COG	N/A	6	0
	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	12/31/2007	End of 2007/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.
					-2,011	-2,011	1
424,199			33,593,205	19,561,717		53,154,922	2
					-100,560	-100,560	3
287,457			12,328,816	11,752,676		24,081,492	4
					-2,473	-2,473	5
329,997			28,677,029	12,893,615		41,570,644	6
					6,354	6,354	7
685,824			25,641,872	28,898,813		54,540,685	8
					-3,766	-3,766	9
486,315			39,911,335	17,374,159		57,285,494	10
					-27,855	-27,855	11
191,259			11,567,160	5,018,205		16,585,365	12
					-3,087	-3,087	13
1,442				77,843		77,843	14
11,048,123			408,693,387	477,859,997	-1,060,565	885,492,819	

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	12/31/2007	End of 2007/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	PCS PHOSPHATE (1)	AD	COG	N/A	N/A	N/A
2	PINELLAS COUNTY (1)	OS	COG	49	62	45
3	PINELLAS COUNTY (1)	AD	COG	N/A	N/A	N/A
4	POLK POWER PARTNERS (1)	OS	COG	107	124	95
5	POLK POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
6	US AGRI-CHEMICALS CORPORATION (1)	OS	COG	N/A	N/A	N/A
7	US AGRI-CHEMICALS CORPORATION (1)	AD	COG	N/A	N/A	N/A
8	RIDGE GENERATING STATION (1)	OS	COG	32	39	26
9	RIDGE GENERATING STATION (1)	AD	COG	N/A	N/A	N/A
10	SI GROUP ENERGY	OS	COG	N/A	6	2
11	SI GROUP ENERGY	AD	COG	N/A	N/A	N/A
12	INTERCHANGE POWER:					
13	CHATTAHOOCHEE, CITY OF	OS				
14	CHATTAHOOCHEE, CITY OF	AD				
	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	12/31/2007	End of 2007/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.
-153					-4,806	-4,806	1
406,187			27,534,870	10,587,077		38,121,947	2
					-10,582	-10,582	3
422,323			47,233,719	14,756,441		61,990,160	4
					1,187	1,187	5
							6
							7
164,435			9,474,213	6,880,408		16,354,621	8
					4,147	4,147	9
18,329				1,024,482		1,024,482	10
					-1,536	-1,536	11
							12
			155,632			155,632	13
					8,065	8,065	14
11,048,123			408,693,387	477,859,997	-1,060,565	885,492,819	

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	12/31/2007	End of 2007/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	COBB ELECTRIC MEMBERSHIP CORP.	OS				
2	CAROLINA PWR. & LIGHT CO.	OS	FERC NO. 5			
3	CALPINE ENERGY SVCS., L.P.	OS	FERC NO. 170			
4	CARGILL-ALLIANT, LLC	OS				
5	CARGILL-ALLIANT, LLC	AD				
6	CENTRAL POWER & LIME	OS				
7	CONSTELLATION ENERGY	OS				
8	DUKE ENERGY TRADING	OS				
9	FLORIDA POWER & LIGHT CO.	OS	FERC NO. 81			
10	FLORIDA MUNICIPAL POWER AGENCY	OS				
11	GEORGIA POWER	OS				
12	GEORGIA TRANSMISSION CORP	OS				
13	HOMESTEAD, CITY OF	OS	FERC NO. 82			
14	JACKSONVILLE ELECTRIC AUTHORITY	OS	FERC NO. 91			
	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	12/31/2007	End of 2007/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.
-153					-4,806	-4,806	1
406,187			27,534,870	10,587,077		38,121,947	2
					-10,582	-10,582	3
422,323			47,233,719	14,756,441		61,990,160	4
					1,187	1,187	5
							6
							7
164,435			9,474,213	6,880,408		16,354,621	8
					4,147	4,147	9
18,329				1,024,482		1,024,482	10
					-1,536	-1,536	11
							12
			155,632			155,632	13
					8,065	8,065	14
11,048,123			408,693,387	477,859,997	-1,060,565	885,492,819	

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.

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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.

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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	JACKSONVILLE ELECTRIC AUTHORITY	AD	FERC NO. 91			
2	LAKELAND, CITY OF	OS	FERC NO. 92			
3	NEW HOPE POWER PARTNERSHIP	OS				
4	NEW SMYRNA BEACH, CITY OF	OS	FERC NO. 104			
5	OGLETHORPE POWER CORP	OS	FERC NO. 139			
6	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86			
7	PJM INTERCONNECTION, LLC	OS				
8	PJM INTERCONNECTION, LLC	AD				
9	RAINBOW ENERGY MARKETING CORP	OS				
10	REEDY CREEK UTILITIES	OS	FERC NO. 119			
11	REEDY CREEK UTILITIES	AD				
12	RELIANT ENERGY SERVICES INC.	OS	FERC NO. 167			
13	RELIANT ENERGY FLORIDA	OS				
14	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128			
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					190	190	1
							2
1,027				121,436		121,436	3
					-50,883	-50,883	4
59				1,062		1,062	5
9,691			1,725,000	1,120,804		2,845,804	6
1,662				99,284		99,284	7
					2,306	2,306	8
208				13,128		13,128	9
13,162			250,000	1,117,962		1,367,962	10
					-588	-588	11
5,217				581,420		581,420	12
283,332			12,741,120	29,212,885		41,954,005	13
62,448				4,237,894		4,237,894	14
11,048,123			408,693,387	477,859,997	-1,060,565	885,492,819	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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:

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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	SHADY HILLS POWER COMPANY	OS				
2	SOUTHERN COMPANY SERVICES INC.	OS	FERC NO. 111			
3	SOUTHERN COMPANY SERVICES INC	AD	FERC NO. 70			
4	SOUTH CAROLINA ELECTRIC & GAS CO	OS				
5	TALLAHASSEE, CITY OF	OS	FERC NO. 122			
6	THE ENERGY AUTHORITY	OS	FERC NO. 175			
7	TAMPA ELECTRIC CO.	OS	FERC NO. 80			
8	TAMPA ELECTRIC CO.	AD				
9	TENNESSEE VALLEY AUTHORITY	OS				
10	CONOCO PHILLIPS	OS				
11	CINCINATTI GAS & ELECTRIC	OS				
12	INADVERTENT INTERCHANGE (NET)	OS				
13	MUNICIPAL ELECT AUTHORTITY OF GA	AD				
14	MERRILL LYNCH	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	12/31/2007	End of 2007/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		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,026,045			21,381,000	108,134,472	-99	129,515,373	1
3,570,751			54,918,942	74,781,287		129,700,229	2
					-367,608	-367,608	3
							4
				269,670	-505,192	-235,522	5
153,943			3,037,500	13,903,175		16,940,675	6
362,669			7,917,204	21,214,236		29,131,440	7
					886	886	8
							9
							10
							11
-223							12
					-20	-20	13
							14
11,048,123			408,693,387	477,859,997	-1,060,565	885,492,819	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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	WILLIAMS POWER COMPANY, INC	OS				
2	WESTAR ENERGY	OS				
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	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		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,378				430,213		430,213	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
11,048,123			408,693,387	477,859,997	-1,060,565	885,492,819	

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	12/31/2007	2007/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: a

OS (1) Cogeneration and small power producers.

COG - Firmed and as available. Cogeneration contracts filed with and approved by the FL Public Service Commission.

* - Glades Electric Cooperative, Inc. is not regulated by FERC or the FL Public Service Commission.

Schedule Page: 326 Line No.: 5 Column: l

OUT OF PERIOD ADJUSTMENT: AUBURNDALE POWER PARTNERS - ENERGY $37,868.

Schedule Page: 326 Line No.: 7 Column: l

OUT OF PERIOD ADJUSTMENT: BAY COUNTY - ENERGY ($895).

Schedule Page: 326 Line No.: 9 Column: l

OUT OF PERIOD ADJUSTMENT: CARGILL FERTILIZER - ENERGY ($41,352).

Schedule Page: 326 Line No.: 11 Column: l

OUT OF PERIOD ADJUSTMENT: CITRUS WORLD - ENERGY $953.

Schedule Page: 326.1 Line No.: 1 Column: l

OUT OF PERIOD ADJUSTMENT: LAKE COUNTY - ENERGY ($2,011).

Schedule Page: 326.1 Line No.: 3 Column: l

OUT OF PERIOD ADJUSTMENT: LAKE COGEN - ENERGY ($100,560).

Schedule Page: 326.1 Line No.: 5 Column: l

OUT OF PERIOD ADJUSTMENT: DADE COUNTY - ENERGY ($2,473).

Schedule Page: 326.1 Line No.: 7 Column: l

OUT OF PERIOD ADJUSTMENT: ORANGE COGEN - ENERGY $6,354.

Schedule Page: 326.1 Line No.: 9 Column: l

OUT OF PERIOD ADJUSTMENT: ORLANDO COGEN - ENERGY ($3,766).

Schedule Page: 326.1 Line No.: 11 Column: l

OUT OF PERIOD ADJUSTMENT: PASCO COGEN - ENERGY ($27,855).

Schedule Page: 326.1 Line No.: 13 Column: l

OUT OF PERIOD ADJUSTMENT: PASCO COUNTY - ENERGY ($3,087).

Schedule Page: 326.2 Line No.: 1 Column: l

OUT OF PERIOD ADJUSTMENT: PCS PHOSPHATE - ENERGY ($4,806).

Schedule Page: 326.2 Line No.: 3 Column: l

OUT OF PERIOD ADJUSTMENT: PINELLAS COUNTY - ENERGY ($10,582).

Schedule Page: 326.2 Line No.: 5 Column: l

OUT OF PERIOD ADJUSTMENT: POLK POWER PARTNERS - ENERGY $1,187.

Schedule Page: 326.2 Line No.: 9 Column: l

OUT OF PERIOD ADJUSTMENT: RIDGE GENERATING STATION - ENERGY $4,147.

Schedule Page: 326.2 Line No.: 11 Column: l

OUT OF PERIOD ADJUSTMENT: SI GROUP ENERGY - ENERGY ($1,536).

Schedule Page: 326.2 Line No.: 14 Column: a

OUT-OF-PERIOD ADJUSTMENT CITY OF CHATTAHOOCHEE - $8065 - CAPACITY

Schedule Page: 326.3 Line No.: 5 Column: a

OUT-OF-PERIOD ADJUSTMENT - CARGILL-ALLIANT - $792

Schedule Page: 326.4 Line No.: 1 Column: a

OUT-OF-PERIOD ADJUSTMENT - JACKSONVILLE ELECTRIC AUTHORITY - $190

Schedule Page: 326.4 Line No.: 8 Column: a

OUT-OF-PERIOD ADJUSTMENT - PJM - $2,306

Schedule Page: 326.4 Line No.: 11 Column: a

OUT-OF-PERIOD ADJUSTMENT - REEDY CREEK UTILITIES - ($588)

Schedule Page: 326.5 Line No.: 3 Column: a

OUT-OF-PERIOD ADJUSTMENT - SOUTHERN COUMPANY SERVICES - ($367608)

Schedule Page: 326.5 Line No.: 8 Column: a

OUT-OF-PERIOD ADJUSTMENT - TAMPA ELECTRIC - $886

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	12/31/2007	2007/Q4

FOOTNOTE DATA

Schedule Page: 326.5 Line No.: 13 Column: a

OUT-OF-PERIOD ADJUSTMENT - MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA - ($20)

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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	Calpine Energy Services	Various	Various	NF
3	Cargill Power Markets, LLC.	Various	Various	NF
4	Cinergy Services, Inc./Fortis	Various	Various	NF
5	Cobb Electric Membership	Various	Various	NF
6	Conoco, Inc.	Various	Various	NF
7	Duke Energy Trading & Mkting	Various	Various	NF
8	Florida Power & Light co.	Various	Various	NF
9	Floirda Municipal Power Authority	Various	Various	NF
10	Gainesville Regional Utilities	Progress Energy Florida	Gainesville Regional	LFP
11	Georgia Power Company	Progress Energy FLorida	Georgia Power Co.	OLF
12	City of Homestead	Progress Energy Florida	City of Homestead	LFP
13	City of Homestead	Progress Energy Florida	City of Homestead	NF
14	Kissimmee Utility Auth	Progress Energy Florida	Kissimmee Utility Auth	LFP
15	Lakeland Utilites	Various	Various	NF
16	City of Mt. Dora	Progress Energy Florida	Various	FNO
17	Utilities Comm of New Smyrna Beach	Progress Energy Florida	Utilites Comm of New Smyrna Beach	LFP
18	Utilities Comm of New Smyrna Beach	Various	Various	NF
19	Oglethorpe Power Corp	Various	Various	NF
20	Orange Cogen LP	Orange Cogen LP	Tampa Electric Company	LFP
21	Orlando Utilities Commission	Progress Energy Florida	Orlando Utilities Commission	LFP
22	Orlando Utilities Commission	Various	Various	NF
23	Rainbow Energy Marketing Corp.	Various	Various	NF
24	Reedy Creek Improvement Dist.	Various	Various	NF
25	Reliant Energy Services	Reliant Energy Svcs	Florida Power & Light	LFP
26	Reliant Energy Services	Various	Various	NF
27	Seminole Electric Coop	Progress Energy Florida	Seminole Electric Coop	SFP
28	Seminole Electric Coop	Various	Various	NF
29	Southern Company of Florida	Various	Various	NF
30	City of Tallahassee	Progress Energy Floirda	City of Tallahassee	LFP
31	City of Tallahassee	City of Tallahassee	City of Tallahassee	LFP
32	City of Tallahassee	Various	Various	NF
33	Tampa Electric Company	Progress Enegy Florida	Tampa Electric Company	SFP
34	Tampa Electric Company	Various	Various	NF
	TOTAL			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
T6/72	Crystal River Sub	Gainesville Regional	1		5,188	1
T6/106	Various	Various		3,888	3,801	2
T6/230C	Various	Various		16,992	16,640	3
T6/104	Various	Various		9,985	9,773	4
T6/114	Various	Various		685	672	5
T6/232C	Various	Various				6
T6/202C	Various	Various				7
T6/7C	Various	Various		2,014	1,971	8
T6/31	Various	Various	19	209	208	9
T6/73	Crystal River Sub	Gainesville Regional	12	98,894	93,706	10
FERC No. 105	Intercession City Sb	Ga Power Company	146			11
T6/130	Various	FL Power & Light	30	216,615	212,208	12
T6/52	Various	FL Power & Light				13
T6/74	Crystal River Sub	Kissimmee Utility	6	45,510	45,510	14
T6/56	Various	Various		1,284	1,255	15
T6/133	Various	City of Mt. Dora		229	225	16
T6/75	Crystal River sub	New Smyrna Beach	5	37,684	37,684	17
T6/12	Various	Various		60,535	59,273	18
T6/187C	Various	Various		30	30	19
T6/77	Orange Sub	Tampa Electric Co	23	73,623	73,623	20
T6/76	Crystal River Sub	Orlando Utilities Cm	13	107,358	107,358	21
T6/10	Various	Various		11,281	11,048	22
T6/35C	Various	Various		11,265	11,044	23
T6/14	Various	Various		1,027	1,008	24
T6/92	Hudson Sub	FL Power & Light		31,317	30,697	25
T6/3	Various	Various		23,452	22,959	26
T6/24	Progress Energy FL	Seminole Elec Coop	14			27
T6/23	Various	Various		31,538	30,719	28
T6/29C	Various	Various				29
T6/96	Progress Energy FL	City of Tallahassee	11	101,972	99,901	30
T6/97	Jackson Bluff Sub	City of Tallahassee	11	6,243	6,120	31
T6/19	Various	Various		472	462	32
T6/25	Progress Enegy FL	Tampa Electric Co.		771,222	755,445	33
T6/160C	Various	Various		22,602	22,128	34
			293	1,973,541	1,939,490	

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	12/31/2007	End of 2007/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.
7,864			7,864	1
7,042			7,042	2
43,881			43,881	3
29,194			29,194	4
29,110			29,110	5
47			47	6
				7
7,432			7,432	8
505			505	9
142,037			142,037	10
592,344			592,344	11
429,480			429,480	12
				13
68,141			68,141	14
3,147			3,147	15
319,337			319,337	16
57,771			57,771	17
120,825			120,825	18
761			761	19
318,363			318,363	20
163,749			163,749	21
31,118			31,118	22
39,926			39,926	23
3,855			3,855	24
1,540,026			1,540,026	25
65,674			65,674	26
198,634			198,634	27
27,401			27,401	28
2,612			2,612	29
163,418			163,418	30
152,261			152,261	31
1,487			1,487	32
3,292,907			3,292,907	33
151,406			151,406	34
40,173,815	0	0	40,173,815	

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	12/31/2007	End of 2007/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	Tampa Electric Company	Tampa Electric Company	Cities of Ft. Meade & Wachula	FNO
2	The Energy Authority	Gainesville Regional Utilities	Gainesville Regional Utililites	LFP
3	The Energy Authority	Various	Various	SFP
4	The Energy Authority	Various	Various	NF
5	City of Winter Park	Progress Energy Florida	City of Winter Park	FNO
6	Eagle Energy Partners I, L.P.	Various	Various	NF
7	Southeastern Power Admin	Various	Various	OS
8	Reedy Creek Improvement Dist.	Various	Various	OS
9	Seminole Electric Cooperative Inc.	Various	Various	OS
10	Florida Municipal Power Auth	Various	Various	OS
11	Alabama Electric Coop	Various	Various	OS
12	PJM	Various	Various	NF
13	Tennessee Valley Authority	Various	Various	NF
14	Carolina Power & Light	Various	Various	NF
15	American Electric Power Svc.	Various	Various	NF
16	Constellation Power Source	Various	Various	NF
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	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	12/31/2007	End of 2007/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.
T6/98	Tampa Electric Co	Ft. Meade & Wachula	2			1
T6/116	Archer Sub	Gainesville Regional		402	394	2
T6/62	Various	Various		46,330	45,403	3
T6/68C	Various	Various		235,743	229,964	4
T6/124	Various	City of Winter Park		978	957	5
T6/258C	Various	Various		2,162	2,116	6
T6	Various	Various				7
T6	Various	Various				8
T6	Various	Various				9
T6/31	Various	Various				10
T6	Various	Various				11
T6	Various	Various				12
T6/70	Various	Various				13
T8	Various	Various				14
T6	Various	Various				15
T8	Various	Various				16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			293	1,973,541	1,939,490	

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	12/31/2007	End of 2007/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.
298,250			298,250	1
82,790			82,790	2
126,262			126,262	3
522,845			522,845	4
1,327,529			1,327,529	5
3,532			3,532	6
272,950			272,950	7
1,815,774			1,815,774	8
22,832,082			22,832,082	9
4,772,884			4,772,884	10
1,021			1,021	11
92,632			92,632	12
10,103			10,103	13
2,371			2,371	14
220			220	15
815			815	16
				17
				18
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40,173,815	0	0	40,173,815	

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	12/31/2007	End of 2007/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	448,009
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Accounting Adjustments	-281,971
7	Service Company Allocations	1,098,731
8	Fleet Transportation Clearing	550,078
9	Stores Burden Adjustment	-1,891,745
10	Inventory Adjustment	2,881,060
11	Florida Sales Tax Audit	6,875,751
12		
13		
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46	TOTAL	9,679,913

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	12/31/2007	End of 2007/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			8,234,048		8,234,048
2	Steam Production Plant	51,839,524	310,657			52,150,181
3	Nuclear Production Plant	18,104,398	1,657			18,106,055
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	53,431,366				53,431,366
7	Transmission Plant	27,345,628				27,345,628
8	Distribution Plant	114,632,769				114,632,769
9	Regional Transmission and Market Operation					
10	General Plant	21,513,149	42,658	19,920		21,575,727
11	Common Plant-Electric					
12	TOTAL	286,866,834	354,972	8,253,968		295,475,774

B. Basis for Amortization Charges

Account 404

Subaccount 370.1 - Meters (Energy Conservation)
Subaccount 398.1 - Miscellaneous Equipment (Energy Conservation)
ASL = 5 Years NSR = 0%
Accrual Rate = 20%

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	12/31/2007	End of 2007/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 2007.	290,638		290,638	
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46	TOTAL	290,638		290,638	

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	12/31/2007	End of 2007/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 $5,000.)
- (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	2007 Nuclear Power Program
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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	12/31/2007	End of 2007/Q4

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 $5,000 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 $5,000 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
	448,009	9302000	448,009		4
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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) 12/31/2007	Year/Period of Report End of 2007/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	75,244,686		
4	Transmission	12,731,451		
5	Regional Market			
6	Distribution	42,887,616		
7	Customer Accounts	18,167,077		
8	Customer Service and Informational	12,071,229		
9	Sales	943,850		
10	Administrative and General	56,084,688		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	218,130,597		
12	Maintenance			
13	Production	42,621,707		
14	Transmission	2,685,463		
15	Regional Market			
16	Distribution	19,231,484		
17	Administrative and General	334,097		
18	TOTAL Maintenance (Total of lines 13 thru 17)	64,872,751		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	117,866,393		
21	Transmission (Enter Total of lines 4 and 14)	15,416,914		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	62,119,100		
24	Customer Accounts (Transcribe from line 7)	18,167,077		
25	Customer Service and Informational (Transcribe from line 8)	12,071,229		
26	Sales (Transcribe from line 9)	943,850		
27	Administrative and General (Enter Total of lines 10 and 17)	56,418,785		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	283,003,348		283,003,348
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2007	End of 2007/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)	283,003,348		283,003,348
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	82,403,375		82,403,375
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	82,403,375		82,403,375
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 Undistrib	7,611,270	113,199	7,724,469
79	Clearing Accounts	7,301,163		7,301,163
80	Misc Deferred Debits	361,973		361,973
81	All Other Accounts	3,577,418	123,867	3,701,285
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	18,851,824	237,066	19,088,890
96	TOTAL SALARIES AND WAGES	384,258,547	237,066	384,495,613

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	12/31/2007	End of 2007/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	499,509	MWH	16,106	363,510		514,270
2	Reactive Supply and Voltage	499,509	MWH	80,378	530,444		668,193
3	Regulation and Frequency Response				69,931		219,925
4	Energy Imbalance				378		33,398
5	Operating Reserve - Spinning				195,870		51,604
6	Operating Reserve - Supplement				1,204		50,123
7	Other						
8	Total (Lines 1 thru 7)	999,018		96,484	1,161,337		1,537,513

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	12/31/2007	End of 2007/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: Monthly Transmission System Peak Load 2007

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	11,707	30	800	7,742	122	620	3,173	50	
2	February	12,409	17	800	7,761	115	620	3,705	208	
3	March	9,566	6	800	6,258	92	620	2,338	258	
4	Total for Quarter 1	33,682			21,761	329	1,860	9,216	516	
5	April	9,529	30	1800	6,792	111	146	2,197	283	
6	May	10,152	4	1700	7,387	124	146	2,262	233	
7	June	11,966	11	1600	8,415	140	146	3,032	233	
8	Total for Quarter 2	31,647			22,594	375	438	7,491	749	
9	July	12,484	9	1700	8,763	140	146	3,202	233	
10	August	13,208	20	1700	9,181	140	146	3,508	233	
11	September	11,958	13	1700	8,512	137	146	2,930	233	
12	Total for Quarter 3	37,650			26,456	417	438	9,640	699	
13	October	10,772	4	1600	7,858	126	146	2,409	233	
14	November	8,363	1	1700	6,088	96	145	1,776	258	
15	December	9,230	18	800	6,378	97	145	2,327	283	
16	Total for Quarter 4	28,365			20,324	319	436	6,512	774	
17	Total Year to Date/Year	131,344			91,135	1,440	3,172	32,859	2,738	

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	20,392,543
4	Nuclear	6,124,417
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	10,358,793
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	36,875,753
10	Purchases	11,048,123
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	1,973,541
17	Delivered	1,939,490
18	Net Transmission for Other (Line 16 minus line 17)	34,051
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	47,957,927

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	39,281,638
23	Requirements Sales for Resale (See instruction 4, page 311.)	5,594,789
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	335,250
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	147,317
27	Total Energy Losses	2,598,933
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	47,957,927

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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 on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

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	3,413,297	26,569	8,803	30	800
30	February	3,387,730	79,018	9,097	17	800
31	March	3,496,496	37,265	6,990	6	800
32	April	3,525,509	34,295	7,473	30	1800
33	May	4,058,618	23,804	8,073	4	1700
34	June	4,465,222	35,041	9,348	11	1600
35	July	4,932,532	30,695	9,792	9	1700
36	August	5,241,940	13,577	10,355	20	1700
37	September	4,461,375	15,050	9,393	13	1700
38	October	4,238,379	2,947	8,568	4	1600
39	November	3,280,565	13,286	6,762	1	1700
40	December	3,456,264	23,703	7,110	18	800
41	TOTAL	47,957,927	335,250			

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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)			1027			454
7	Plant Hours Connected to Load			14379			17915
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			1048			464
10	When Limited by Condenser Water			1006			444
11	Average Number of Employees			76			74
12	Net Generation, Exclusive of Plant Use - KWh			3289292000			1468601000
13	Cost of Plant: Land and Land Rights			1869309			2046939
14	Structures and Improvements			37686948			19501549
15	Equipment Costs			249711763			126015497
16	Asset Retirement Costs			315962			1929969
17	Total Cost			289583982			149493954
18	Cost per KW of Installed Capacity (line 17/5) Including			260.3236			302.3990
19	Production Expenses: Oper, Supv, & Engr			118792			6519
20	Fuel			272653659			126329527
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			85707			84665
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			700			1187
26	Misc Steam (or Nuclear) Power Expenses			6339609			4123556
27	Rents			0			0
28	Allowances			1910468			884822
29	Maintenance Supervision and Engineering			663333			860093
30	Maintenance of Structures			1014015			104113
31	Maintenance of Boiler (or reactor) Plant			1670813			920544
32	Maintenance of Electric Plant			279371			174634
33	Maintenance of Misc Steam (or Nuclear) Plant			4732947			3260041
34	Total Production Expenses			289469414			136749701
35	Expenses per Net KWh			0.0880			0.0931
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	4714723	2963417	0	2411800	52661	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	156993	1036	0	156200	1032	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	52.576	8.435	0.000	51.827	7.403	0.000
41	Average Cost of Fuel per Unit Burned	52.506	8.435	0.000	52.154	7.403	0.000
42	Average Cost of Fuel Burned per Million BTU	7.963	8.144	0.000	7.950	7.174	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.084	0.000	0.086	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	10363.000	0.000	10813.000	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: *Crystal River South* (d)	Plant Name: *Crystal River North* (e)	Plant Name: *Crystal River* (f)	Line No.
Steam	Steam	Nuclear	1
Conventional	Conventional	Conventional	2
1966	1982	1977	3
1969	1984	1977	4
964.35	1478.52	890.46	5
874	1456	779	6
14520	16714	7898	7
0	0	0	8
882	1468	788	9
866	1444	769	10
160	240	567	11
4804641000	10531360000	6124417000	12
2512007	0	-150918	13
75347012	149656838	225676958	14
376418274	774924634	584351702	15
3683195	0	50846	16
457960488	924581472	809928588	17
474.8903	625.3426	909.5620	18
553235	715612	1231265	19
152908891	343276499	30323189	20
0	0	3634057	21
2390904	4242890	10829485	22
0	0	0	23
0	0	0	24
0	0	8254	25
5213487	7369597	39128068	26
0	0	0	27
2557165	4026053	0	28
165647	224618	9826499	29
700148	141930	1537159	30
5412767	2669464	17510007	31
1266049	505946	2650445	32
14750597	8477283	2619148	33
185918890	371649892	119297576	34
0.0387	0.0353	0.0195	35

(d)			(e)			(f)			Line No.
Oil	Coal		Oil	Coal		Oil	Nuclear		36
BBL	Tons		BBL	Tons		BBL	MMBTU		37
14103	1956950	0	57611	4150809	0	415	62811518	0	38
138348	12263	0	139144	12165	0	138554	0	0	39
95.196	79.085	0.000	91.403	79.693	0.000	0.000	0.000	0.000	40
106.090	79.490	0.000	94.911	79.688	0.000	0.000	0.456	0.000	41
18.258	3.241	0.000	16.241	3.275	0.000	0.000	0.456	0.000	42
0.000	0.032	0.000	0.000	0.031	0.000	0.000	0.005	0.000	43
0.000	9989.000	0.000	0.000	9589.000	0.000	0.000	10256.000	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: *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)	138			205		
7	Plant Hours Connected to Load	9430			1537		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	146			232		
10	When Limited by Condenser Water	129			178		
11	Average Number of Employees	40			5		
12	Net Generation, Exclusive of Plant Use - KWh	298649000			56474000		
13	Cost of Plant: Land and Land Rights	22059			1597635		
14	Structures and Improvements	5100438			1650590		
15	Equipment Costs	30544020			22526013		
16	Asset Retirement Costs	2366374			0		
17	Total Cost	38032891			25774238		
18	Cost per KW of Installed Capacity (line 17/5) Including	258.7271			113.6430		
19	Production Expenses: Oper, Supv, & Engr	4253			330704		
20	Fuel	24706636			11585068		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	146867			152757		
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	2513951			379842		
27	Rents	0			0		
28	Allowances	58752			0		
29	Maintenance Supervision and Engineering	17217			0		
30	Maintenance of Structures	57442			0		
31	Maintenance of Boiler (or reactor) Plant	227129			0		
32	Maintenance of Electric Plant	880253			23260		
33	Maintenance of Misc Steam (or Nuclear) Plant	1115213			564480		
34	Total Production Expenses	29727713			13036111		
35	Expenses per Net KWh	0.0995			0.2308		
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	244811	2038236	0	127279	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	155538	1032	0	138680	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	62.571	4.833	0.000	92.292	0.000	0.000
41	Average Cost of Fuel per Unit Burned	60.189	4.833	0.000	90.086	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	9.214	4.683	0.000	15.467	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.118	0.000	0.000	0.203	0.000	0.000
44	Average BTU per KWh Net Generation	12840.000	0.000	0.000	13127.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

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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
		711			1084			176	6
		3512			12653			2869	7
		0			0			0	8
		779			1184			199	9
		642			984			153	10
		20			39			2	11
		165597000			762370000			117482000	12
		2113330			746305			0	13
		9680676			15822838			1471200	14
		145262126			241591401			29395982	15
		0			0			0	16
		157056132			258160544			30867182	17
		182.3647			197.0390			168.1219	18
		1822401			1856492			180762	19
		23746880			97881081			13664360	20
		0			0			0	21
		36796			33634			2756	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		956684			1723628			256066	26
		0			0			0	27
		0			0			0	28
		350			203803			0	29
		36959			0			0	30
		0			0			0	31
		0			4970			149818	32
		961402			1745708			436179	33
		27561472			103449316			14689941	34
		0.1664			0.1357			0.1250	35
Oil	Gas		Oil	Gas		Oil	Gas		36
BBL	MCF		BBL	MCF		BBL	MCF		37
133868	1489720	0	137856	8434988	0	36156	1423055	0	38
138482	1035	0	138203	1021	0	137095	1035	0	39
93.184	8.430	0.000	94.735	10.081	0.000	117.170	7.252	0.000	40
82.873	8.430	0.000	91.537	10.081	0.000	89.789	7.252	0.000	41
14.248	8.145	0.000	15.770	9.876	0.000	15.594	7.003	0.000	42
0.200	0.000	0.000	0.195	0.000	0.000	0.223	0.000	0.000	43
14013.000	0.000	0.000	12344.000	0.000	0.000	14314.000	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: *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)	201			175		
7	Plant Hours Connected to Load	1674			819		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	226			201		
10	When Limited by Condenser Water	176			148		
11	Average Number of Employees	4			0		
12	Net Generation, Exclusive of Plant Use - KWh	54709000			39624000		
13	Cost of Plant: Land and Land Rights	0			824781		
14	Structures and Improvements	1074388			1394020		
15	Equipment Costs	25861627			21744081		
16	Asset Retirement Costs	0			586346		
17	Total Cost	26936015			24549228		
18	Cost per KW of Installed Capacity (line 17/5) Including	120.8977			135.6461		
19	Production Expenses: Oper, Supv, & Engr	493239			437528		
20	Fuel	8190121			8885047		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	6838			8258		
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	301204			218237		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	6131			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	66501			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	2294857			200328		
34	Total Production Expenses	11358891			9749398		
35	Expenses per Net KWh	0.2076			0.2460		
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	31230	629130	0	100546	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	139388	1036	0	139371	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	93.574	8.473	0.000	89.782	0.000	0.000
41	Average Cost of Fuel per Unit Burned	90.287	8.473	0.000	86.672	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	15.422	8.181	0.000	14.807	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.235	0.000	0.000	0.220	0.000	0.000
44	Average BTU per KWh Net Generation	15251.000	0.000	0.000	14854.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

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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
		60			123			214	6
		674			1833			4824	7
		0			0			0	8
		70			133			225	9
		49			113			204	10
		0			3			12	11
		14103000			41093000			850275000	12
		65917			184271			0	13
		405755			791388			10620577	14
		9430272			16663593			70755124	15
		0			0			0	16
		9901944			17639252			81375701	17
		146.5218			114.9661			292.6131	18
		444284			221531			1347729	19
		2329372			5963196			54151227	20
		0			0			0	21
		6552			201395			149852	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		131854			215998			543926	26
		0			0			0	27
		0			0			0	28
		7677			0			0	29
		0			922			0	30
		0			0			0	31
		0			45997			356894	32
		151484			712657			1921383	33
		3071223			7361696			58471011	34
		0.2178			0.1791			0.0688	35
Oil	Gas		Oil	Gas		Gas			36
BBL	MCF		BBL	MCF		MCF			37
7508	197817	0	2041	689828	0	6379792	0	0	38
139099	1035	0	137153	1035	0	1033	0	0	39
92.595	8.463	0.000	63.325	8.530	0.000	8.488	0.000	0.000	40
86.118	8.463	0.000	37.899	8.530	0.000	8.488	0.000	0.000	41
14.741	8.175	0.000	6.579	8.238	0.000	8.218	0.000	0.000	42
0.260	0.000	0.000	0.000	0.146	0.000	0.064	0.000	0.000	43
17631.000	0.000	0.000	0.000	17669.000	0.000	7750.000	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	12/31/2007	End of 2007/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: *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)	15			46		
7	Plant Hours Connected to Load	86			7561		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	16			47		
10	When Limited by Condenser Water	12			46		
11	Average Number of Employees	0			11		
12	Net Generation, Exclusive of Plant Use - KWh	1007000			354104000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	117906			6499783		
15	Equipment Costs	3441553			35048107		
16	Asset Retirement Costs	0			0		
17	Total Cost	3559459			41547890		
18	Cost per KW of Installed Capacity (line 17/5) Including	184.5235			966.2300		
19	Production Expenses: Oper, Supv, & Engr	40997			441953		
20	Fuel	272130			24394591		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	3278			12400		
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	11079			75718		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			306464		
30	Maintenance of Structures	17095			33886		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			536684		
33	Maintenance of Misc Steam (or Nuclear) Plant	1990			1781528		
34	Total Production Expenses	346569			27583224		
35	Expenses per Net KWh	0.3442			0.0779		
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	3061	0	0	3308176	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138867	0	0	1033	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	93.409	0.000	0.000	7.167	0.000	0.000
41	Average Cost of Fuel per Unit Burned	86.228	0.000	0.000	7.167	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	14.784	0.000	0.000	6.938	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.262	0.000	0.000	0.067	0.000	0.000
44	Average BTU per KWh Net Generation	17729.000	0.000	0.000	9650.000	0.000	0.000

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2007	End of 2007/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: *Hines Energy Complex* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Gas Turbine			1
Conventional			2
1999			3
2007			4
2265.75	0.00	0.00	5
2054	0	0	6
21190	0	0	7
0	0	0	8
2177	0	0	9
1930	0	0	10
50	0	0	11
7901955000	0	0	12
11012624	0	0	13
121737261	0	0	14
929395015	0	0	15
0	0	0	16
1062144900	0	0	17
468.7829	0.0000	0.0000	18
85640	0	0	19
494945095	0	0	20
0	0	0	21
4667345	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
2781552	0	0	26
0	0	0	27
0	0	0	28
3426	0	0	29
0	0	0	30
0	0	0	31
943494	0	0	32
8058628	0	0	33
511485180	0	0	34
0.0647	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Oil	Gas								36
BBL	MCF								37
22335	55815552	0	0	0	0	0	0	0	38
452264	1020	0	0	0	0	0	0	0	39
96.961	8.826	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
61.723	8.826	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
3.249	8.652	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.063	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	7260.000	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	12/31/2007	End of 2007/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 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 On Structures of Another Line (g)	Number Of 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								
11	230 KV LINES	OVERHEAD						
12	AVON PARK	FORT MEADE	230.00	230.00	ST	4.30		1
13					CP	2.01		
14					WH	19.86		
15					WP	0.94		
16					SP		1.22	
17	AVON PARK	FISHEATING CREEK	230.00	230.00	SP	9.02		1
18					CP	17.05		
19					WH	3.29		
20	ANCLOTE PLANT	LARGO	230.00	230.00	SH	15.29		1
21					SP	8.54		
22	ANCLOTE PLANT	EAST CLEARWATER	230.00	230.00	SH		15.30	1
23	ANCLOTE PLANT	SEVEN SPRINGS	230.00	230.00	SP	7.71		1
24	ALTAMONTE	WOODSMERE	230.00	230.00	WP	0.10		1
25					ST		0.56	
26					WH	10.99		
27					SP	0.82		
28	BARCOLA	CITY OF LAKELAND TIE	230.00	230.00	WH	18.68		1
29	BARCOLA	PEBBLEDALE	230.00	230.00	CP	3.86		1
30	BROOKRIDGE	BROOKRIDGE	230.00	230.00	WP	0.21		1
31	CRYSTAL RIVER	CURLEW	230.00	230.00	ST	77.88	78.14	1
32	CRYSTAL RIVER	CENTRAL FLORIDA	230.00	230.00	ST	53.36	39.59	1
33	CRYSTAL RIVER	FT. WHITE	230.00	230.00	WH	73.31		1
34	CENTRAL FLORIDA	SILVER SPRINGS	230.00	230.00	ST	28.32	5.15	1
35	CENTRAL FLORIDA	SORRENTO	230.00	230.00	CP	14.65		1
36					TOTAL	4,341.59	543.02	77

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)	
								1
2156 KCM ACSR	2,282,211	20,841,657	23,123,868					2
2335 KCM ACSR	12,767	12,252,818	12,265,585					3
2335 KCM ACSR								4
2335 KCM ACSR	9,840	8,806,860	8,816,700					5
								6
								7
2500 KCM CU		2,088,494	2,088,494					8
2500 KCM CU	251,470	2,109,689	2,361,159					9
								10
								11
1081 KCM ACSR	85,476	3,650,585	3,736,061					12
954 KCM ACSR								13
954 KCM ACSR								14
954 KCM ACSR								15
954 KCM ACSR								16
1590 KCM ACSR	1,321,547	8,826,467	10,148,014					17
1590 KCM ACSR								18
1590 KCM ACSR								19
1590 KCM ACSR	389,829	5,723,911	6,113,740					20
1590 KCM ACSR								21
1590 KCM ACSR		635,748	635,748					22
2335 KCM ACAR	1,145,863	1,387,207	2,533,070					23
1590 KCM ACSR	43,803	1,560,980	1,604,783					24
1590 KCM ACSR								25
1590 KCM ACSR								26
1590 KCM ACSR								27
1590 KCM ACSR	133,007	3,101,790	3,234,797					28
1622 KCM		3,429,434	3,429,434					29
1590 KCM ACSR		110,272	110,272					30
1590 KCM ACSR	1,256,635	11,763,056	13,019,691					31
1590 KCM ACSR	774,675	7,013,774	7,788,449					32
954 KCM ACSR	219,431	7,349,695	7,569,126					33
1590 KCM ACSR	439,516	3,270,960	3,710,476					34
1590 KCM ACSR	1,621,137	10,461,338	12,082,475					35
	65,189,993	718,104,360	783,294,353	36,856	7,040,485		7,077,341	36

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2007	End of 2007/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					SP	14.82		
2	CENTRAL FLORIDA	WINDERMERE	230.00	230.00	ST	69.74	46.61	1
3	CRAWFORDVILLE	PERRY	230.00	230.00	ST	12.09		1
4					WH	40.35		
5	CRAWFORDVILLE	PORT ST. JOE	230.00	230.00	WH	58.85		1
6					SP	2.65		
7					SH	0.65		
8	CRYSTAL RIVER EAST	SEVEN SPRINGS	230.00	230.00	ST		2.90	1
9	DEBARY	ALTAMONTE	230.00	230.00	SP	3.40	8.66	1
10					WH	3.06		
11					ST	0.56	3.23	
12					CP	0.49	0.32	
13	DEBARY	DELAND WEST	230.00	230.00	WH	7.15		1
14					WP	1.94		
15					CP	1.13		
16	DEBARY	NORTH LONGWOOD	230.00	230.00	WH	1.32		1
17					CH		2.70	
18					ST	3.36		
19					CP	0.42		
20					SP	9.15		
21	DEARMAN	SILVER SPRINGS NORTH	230.00	230.00	CP	4.27		1
22					ST		1.21	
23	DEBARY	WINTER SPRINGS	230.00	230.00	WH	3.23		1
24					SP	16.78		
25					ST	0.58		
26	FORT WHITE	SILVER SPRINGS	230.00	230.00	ST	1.46		1
27					SL	4.99		
28					CH	64.80		
29					CP	3.21		
30	40TH ST	PASADENA FSP	230.00	230.00	CP	0.19		1
31					SP	3.66		
32	FORT MEADE	VANDOLAH	230.00	230.00	SP	1.20		1
33					WH	21.05		
34					CP	1.80		
35	FORT MEADE	WEST LAKE WALES	230.00	230.00	ST	3.07		1
36					TOTAL	4,341.59	543.02	77

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2007	End of 2007/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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1590 KCM ACSR								1
1590 KCM ACSR	1,128,343	7,369,724	8,498,067					2
954 KCM ACSR	1,203,558	4,148,014	5,351,572					3
954 KCM ACSR								4
954 KCM ACSR	614,777	5,362,326	5,977,103					5
954 KCM ACSR								6
954 KCM ACSR								7
1590 KCM ACSR	66,391	139,498	205,889					8
1590 KCM ACSR	271,527	2,228,275	2,499,802					9
1590 KCM ACSR								10
1590 KCM ACSR								11
1590/1431 KCM								12
1590 KCM ACSR	809,746	3,100,944	3,910,690					13
1590 KCM ACSR								14
1590 KCM ACSR								15
954 KCM ACSR	197,330	2,861,821	3,059,151					16
954 KCM ACSR								17
1590 KCM ACSR								18
1431 KCM ACSR								19
1590 KCM ACSR								20
954 KCM ACSR	195,181	1,613,873	1,809,054					21
954 KCM ACSR								22
1590 KCM ACSR	1,073,673	10,734,866	11,808,539					23
1590 KCM ACSR								24
1590 KCM ACSR								25
795 KCM ACSR	449,980	4,431,032	4,881,012					26
795 KCM ACSR								27
795 KCM ACSR								28
954 KCM ACSR								29
1590 KCM ACSR	2,510	887,094	889,604					30
1590 KCM ACSR								31
954 KCM ACSR	63,923	3,932,745	3,996,668					32
954 KCM ACSR								33
954 KCM ACSR								34
1081 KCM ACAR	55,284	2,878,059	2,933,343					35
	65,189,993	718,104,360	783,294,353	36,856	7,040,485		7,077,341	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/Q4

TRANSMISSION LINE STATISTICS

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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 On Structures of Another Line (g)	Number Of Circuits (h)
1					WH	16.80		
2					SP	2.90		1
3	TIGER BAY	TECO	230.00	230.00	CP	0.10		1
4					ST	5.86		
5					WH	1.38		
6	HINES ENERGY	FORT MEADE	230.00	230.00	SP	6.45		1
7	HINES ENERGY	BARCOLA	230.00	230.00	SP	3.09		1
8	HINES ENERGY	BARCOLA (2ND CIRCUIT)	230.00	230.00	SP	3.09		1
9	HINES ENERGY	TIGER BAY	230.00	230.00	SP	0.64	3.51	
10	HINES PLANT	HINES	230.00	230.00	SP	1.64		
11	HINES	WEST LAKE WALES	230.00	230.00	SP	20.57		1
12	OLD SUB NORTH	NEW SUB NORTH	230.00	230.00	SP	0.22		1
13	INTERCESSION CITY	LAKE BRYAN 2ND CIRCUIT	230.00	230.00	SP	7.84		1
14	KATHLEEN	WEST LAKELAND	230.00	230.00	WH	14.50		1
15					CP	1.31		
16	KATHLEEN	ZEPHYRHILLS NORTH	230.00	230.00	WH	0.83		1
17					CP	8.70		
18					WP	1.35		
19	LARGO	PASADENA	230.00	230.00	ST		1.61	1
20					SP	13.13		
21	LAKE TARPON	CURLEW	230.00	230.00	ST	4.32		1
22	LAKE TARPON	HIGGINS	230.00	230.00	CP	2.57		1
23					SP	3.02		
24	LAKE TARPON	LARGO	230.00	230.00	SP	14.49		1
25					CP	2.90		
26	LAKE TARPON	SEVEN SPRINGS	230.00	230.00	ST	2.90		1
27	LAKE TARPON	TECO EXIST	230.00	230.00	ST	0.68		1
28					SP	0.81		
29	NORTHEAST	CURLEW	230.00	230.00	ST	16.95	12.78	1
30	NORTHEAST	40TH ST.	230.00	230.00	CP	0.16		1
31					SP	8.16		
32	NORTH LONGWOOD	PIEDMONT	230.00	230.00	SP	0.31	4.04	1
33					WH	6.16		
34	NORTH LONGWOOD	FP&L CO TIE	230.00	230.00	SP	4.04		1
35					WH	2.77		
36					TOTAL	4,341.59	543.02	77

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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.
1081 KCM ACAR								1
1622 ACSS/TW								2
1590/1081 KCM	202,353	133,977	336,330					3
1081 KCM ACAR								4
1081/954 KCM								5
954 KCM ACSR		2,778,770	2,778,770					6
954 KCM ACSR		1,454,283	1,454,283					7
954 KCM ACSR		1,396,088	1,396,088					8
954 KCM ACSR		1,423,104	1,423,104					9
954 KCM ACSR		1,608,580	1,608,580					10
1622 ACSS/TW	6,148,371	39,330,698	45,479,069					11
2335 KCM ACAR		194,088	194,088					12
1622 ACSS TW		5,947,649	5,947,649					13
1590 KCM ACSR	485,915	2,927,971	3,413,886					14
1590 KCM ACSR								15
1590 KCM ACSR	275,097	3,029,080	3,304,177					16
1590 KCM ACSR								17
1590 KCM ACSR								18
1590 KCM ACSR	152,473	3,055,983	3,208,456					19
1590 KCM ACSR								20
1590 KCM ACSR		955,417	955,417					21
1590 KCM ACSR	15,699	1,499,798	1,515,497					22
1590 KCM ACSR								23
1590 KCM ACSR	412,563	8,596,422	9,008,985					24
1590 KCM ACSR								25
1590 KCM ACSR	189,338	694,404	883,742					26
1590 KCM ACSR		197,855	197,855					27
1590 KCM ACSR								28
1590 KCM ACSR	1,517,258	2,482,574	3,999,832					29
1590 KCA ACSR	288,076	1,390,094	1,678,170					30
1081 KCA ACAR								31
954 KCM ACSR	16,834	1,411,376	1,428,210					32
954 KCM ACSR								33
954 KCM ACSR	207,841	1,295,070	1,502,911					34
954 KCM ACSR								35
	65,189,993	718,104,360	783,294,353	36,856	7,040,485		7,077,341	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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 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 On Structures of Another Line (g)	Number Of Circuits (h)
1	NORTH LONGWOOD	RIO PINAR	230.00	230.00	SP	0.58	3.94	1
2					CP	0.21		
3					AT	10.91		
4	NEWBERRY	WILCOX	230.00	230.00	SP	19.33		1
5	NORTHEAST	PINELLAS	230.00	230.00	CP	1.90		1
6	PIEDMONT	SORRENTO	230.00	230.00	SP	4.24		1
7					CP	6.45		
8					WH	4.79		
9	PIEDMONT	WOODSMERE	230.00	230.00	WH	6.72		1
10	PORT ST. JOE	GULF POWER	230.00	230.00	ST	33.99		1
11	RIO PINAR	OUC TIE	230.00	230.00	SP	0.52		1
12					AT	2.19		
13	SILVER SPRINGS	DELAND WEST	230.00	230.00	SL	39.93		1
14					SH	0.92		
15					SP	1.57		
16	SUWANNEE RIVER PLANT	FORT WHITE	230.00	230.00	ST	38.08		1
17	SKY LAKE	OUC TIE	230.00	230.00	CP	2.40		1
18					WP	2.22		
19	SUWANNEE	PERRY	230.00	230.00	ST	28.61		1
20	SUWANNEE PEAKERS	SUWANNEE	230.00	230.00	WH	0.63		1
21	SUWANNEE	GEORGIA GPC TIE	230.00	230.00	ST	18.36		1
22	TIGER BAY	FORT MEADE 2	230.00	230.00	SP	0.44	1.78	1
23	ULMERTON	LARGO	230.00	230.00	ST	5.05		1
24	VANDOLAH	SEMINOLE	230.00	230.00	SP	0.03		1
25	VANDOLAH	WHIDDEN	230.00	230.00	SP	14.40		1
26	WINDERMERE	INTERCESSION CITY	230.00	230.00	WH	9.80		1
27					CP	0.27		
28					SP	5.33	4.85	
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	29.34		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	4,341.59	543.02	77

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	12/31/2007	End of 2007/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.
1590 KCM ACSR	420,736	1,828,798	2,249,534					1
954 KCM ACSR								2
954 KCM ACSR								3
1590 KCM ACSR	75,328	5,772,719	5,848,047					4
954 KCM ACSR		4,498	4,498					5
1590 KCM ACSR	574,273	5,183,703	5,757,976					6
1590 KCM ACSR								7
1590 KCM ACSR								8
954 KCM ACSR	15,605	535,794	551,399					9
795 KCM ACSR	71,747	2,336,296	2,408,043					10
954 KCM ACSR	100,034	2,066,610	2,166,644					11
954 KCM ACSR								12
1590 KCM ACSR	54,890	6,782,807	6,837,697					13
1590 KCM ACSR								14
1590 KCM ACSR								15
954 KCM ACSR	196,750	2,362,830	2,559,580					16
954 KCM ACSR	121,530	1,297,008	1,418,538					17
954 KCM ACSR								18
795 KCM ACSR	151,754	1,320,102	1,471,856					19
795 KCM ACSR		8,063	8,063					20
954 KCM ACSR	104,190	1,110,105	1,214,295					21
954 KCM ACSR		739,819	739,819					22
1590 KCM ACSR	601,048	1,759,896	2,360,944					23
954 ACSS TW		185,786	185,786					24
1622 ACSS TW		14,225,839	14,225,839					25
954 KCM ACSR	135,968	5,359,603	5,495,571					26
954 KCM								27
1622ACSS TW								28
1590 KCM ACSR	19,739	1,019,195	1,038,934					29
1590 KCM ACSR								30
954/1081 KCM	364,444	3,288,996	3,653,440					31
1622ACSS TW								32
954 KCM ACSR	595,327	5,123,972	5,719,299					33
954 KCM ACSR	17,342	232,082	249,424					34
954 KCM ACSR		513,323	513,323					35
	65,189,993	718,104,360	783,294,353	36,856	7,040,485		7,077,341	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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 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	WOODSMERE	OUC TIE	230.00	230.00	ST		0.92	1
2								
3	OTHER TRANS. LINES	OVERHEAD 115 & 69				2,846.42	304.00	
4	OTHER TRANS. LINES	UNDERGROUND 115				47.29		
5								
6	Total Overhead Transmission	Line Expenses				4,341.59	543.02	77
7		(230, 115, 69 Kv)						
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
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21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,341.59	543.02	77

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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
	35,449,908	396,948,386	432,398,294					3
	88,132	12,217,364	12,305,496					4
				36,856	7,040,485		7,077,341	5
	65,189,993	718,104,360	783,294,353	36,856	7,040,485		7,077,341	6
								7
								8
								9
								10
								11
								12
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								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	65,189,993	718,104,360	783,294,353	36,856	7,040,485		7,077,341	36

Schedule Page: 422.4 Line No.: 35 Column: f

2007 transmission pole mile statistics have been updated to reflect current and prior year minor additions.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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	CLERMONT EAST	MONTVERDE	1.65	CP	11.00	1	1
2	WOODSMERE	CLERMONT EAST (RETIRE)	-1.77	CP/WP			
3	IO-289	IO 289-115	8.87	CP	12.00	1	1
4	QUINCY	QX-139	17.98	CP	11.00	1	1
5	TZ-292 TAP	LAND-O-LAKES	0.71	CP	17.00	2	2
6	FORT MEADE	WEST LK WALES	2.90	SP	9.00	1	1
7	HINES (HWLW-1)	WEST LAKE WALES	20.57	SP	9.00	1	2
8	HUDSON	HUDSON (WREC)	3.49	CP	16.00	1	1
9	GINNIE	HIGH SPRINGS	4.32	CP	11.00	1	1
10	GINNIE	HIGH SPRINGS (RETIRE)	-4.32	WP/SP			
11	VANDOLAH	SEMINOLE ELECTRIC	0.03	SP	1.00	1	1
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
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31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		54.43		97.00	10	11

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	12/31/2007	End of 2007/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.
1272	ACSS/TW	V	115		419,771	140,649		560,420	1
795	AAC	V	69				-745,265	-745,265	2
795	ACSR	V	69	773,793	2,871,044	1,263,292		4,908,129	3
795	ACSR	V	115		961,850	175,457		1,137,307	4
795	AAC	V	69		253,199	113,006	-431,933	-65,728	5
1622	ACSS/TW	V	230		189,779	744,344		934,123	6
1622	ACSS/TW	V	230	6,148,371	26,629,443	12,701,255		45,479,069	7
1622	ACCS/TW	V	115	217,703	557,000	1,675,747		2,450,450	8
795	ACSR	V	69		1,619,853	213,983		1,833,836	9
2/0	COPPER	V	69				-129,455	-129,455	10
954	ACSS/TW	V	230		90,232	47,042		137,274	11
									12
									13
									14
									15
									16
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				7,139,867	33,592,171	17,074,775	-1,306,653	56,500,160	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	12/31/2007	End of 2007/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 - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	40TH STREET - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
3	51ST STREET - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
4	ALDERMAN - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
5	ANCLOTE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
6	BAYBORO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	BAYVIEW - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	BAYWAY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
9	BELLEAIR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	BROOKER CREEK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	BROOKSVILLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	12.00
12	BROOKSVILLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	7.00
13	BROOKSVILLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	13.00
14	BROOKSVILLE ROCK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	2.00	
15	BUSHNELL - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	CAMPS SECTION 7 MINE-SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
17	CENTER HILL - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	CENTRAL PLAZA - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
19	CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	CONSOLIDATED ROCK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
21	CROSS BAYOU - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	CROSSROADS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	CURLEW - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	DENHAM - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	DISSTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
26	DISSTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
27	DUNEDIN - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	14.00
29	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	240.00	120.00	
30	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
31	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	ELFERS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
33	FLORAL CITY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	FLORA-MAR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
35	FLORIDA ROCK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	66.00	3.00	
36	G.E. PINELLAS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	GATEWAY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
38	HAMMOCK - SUNCOAST FLORDAI REGION	DIST - UNATTENDED	115.00	4.00	
39	HAMMOCK - SUNCOAST FLORDAI REGION	DIST - UNATTENDED	67.00	4.00	
40	HIGHLANDS - SUNCOAST 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) 12/31/2007	Year/Period of Report End of 2007/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
90	3					4
100	2					5
60	2					6
100	2					7
40	1					8
80	2					9
60	2					10
150	1					11
100	1					12
60	2					13
9	1	1				14
13	1					15
19	2	1				16
13	1	1				17
60	2					18
120	4					19
2	1	1				20
150	3					21
80	2					22
90	3					23
90	3					24
150	1					25
80	2					26
60	3					27
200	1					28
200	1					29
250	1					30
150	3					31
100	2					32
13	1					33
100	2					34
12	2	2				35
29	2					36
90	3					37
20	1					38
19	2					39
80	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	12/31/2007	End of 2007/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	KENNETH CITY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	LAND-O-LAKES - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
3	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
4	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
5	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	5.00
6	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	MAXIMO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	NEW PORT RICHEY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
9	NORTHEAST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	15.00
10	NORTHEAST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	OAKHURST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	PALM HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
13	PALM HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	PASADENA - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
15	PASADENA - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
16	PILSBURY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
17	PINELLAS WELL FIELD - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	66.00	3.00	
18	PORT RICHEY WEST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
19	SAFETY HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
20	SEMINOLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
21	SEMINOLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	SEVEN SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	SEVEN SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
24	SIXTEENTH ST. - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
25	STARKEY ROAD - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	TANGERINE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	8.00
27	TARPON SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	
28	TARPON SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
29	TAYLOR AVE. - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	TRI-CITY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
31	TRILBY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
32	ULMERTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	14.00
33	ULMERTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
34	ULMERTON WEST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	VINOY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
36	WALSINGHAM - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	ZEPHYRHILLS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	ZEPHYRHILLS NORTH - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
39	ZEPHYRHILLS NORTH - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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
30	1					2
200	1					3
200	1					4
200	1					5
100	2					6
150	3					7
60	2					8
400	2					9
100	2					10
90	3					11
250	1					12
60	2					13
250	1					14
80	2					15
100	2					16
5	1	1				17
90	3					18
80	2					19
250	1					20
100	2					21
60	2					22
750	3					23
80	2					24
80	2					25
60	2					26
150	1					27
100	2					28
80	2					29
60	2					30
9	1	1				31
450	2					32
100	2					33
80	2					34
100	2					35
100	2					36
60	2					37
250	1					38
60	2					39
						40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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					
2	ALACHUA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	APALACHICOLA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	ARCHER - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
5	ARCHER - NORTH FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
6	BEACON HILL - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	CARRABELLE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	CARRABELLE BEACH - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
9	CRAWFORDVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
10	CRAWFORDVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
11	CROSS CITY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	EAST POINT - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	FOLEY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	FORT WHITE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
15	FORT WHITE - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	4.00
16	FORT WHITE - NORTH FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
17	G.E. ALACHUA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	GAINESVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
19	GEORGIA PACIFIC - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	HIGH SPRINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	HIGH SPRINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	7.00	
22	HULL ROAD - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	INDIAN PASS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	JASPER - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
25	JASPER - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	JENNINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
27	LURAVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	MADISON - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
29	MONTICELLO - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	NEWBERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
31	NEWBERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
32	O'BRIEN - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	OCCIDENTAL #1 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
34	OCCIDENTAL #1 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	
35	OCCIDENTAL #2 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
36	OCCIDENTAL #3 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
37	OCCIDENTAL SWIFT CREEK#1-NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
38	OCCIDENTAL SWIFT CREEK#2-NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	
39	OCCIDENTAL SWIFT CREEK#2-NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
40	OCHLOCKONEE - NORTH 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	12/31/2007	End of 2007/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.
						1
13	1	1				2
13	1	1				3
150	1					4
16	2	2				5
13	1	1				6
13	1	1				7
10	1	1				8
100	1					9
13	1	1				10
13	1	1				11
13	1	1				12
40	2					13
100	1					14
75	1					15
6	1	1				16
20	1					17
30	1					18
10	1	1				19
9	1					20
13	1	1				21
19	2					22
5	1	1				23
60	1					24
13	1	1				25
2	1	1				26
9	1	1				27
40	2					28
40	2					29
100	1					30
13	1	1				31
6	1	1				32
50	1					33
25	1					34
40	2					35
13	1					36
60	3					37
20	1					38
30	1					39
20	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	12/31/2007	End of 2007/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	PERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
2	PERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	PERRY NORTH - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	PORT ST. JOE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
5	PORT ST. JOE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	PORT ST. JOE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
7	RIVER JUNCTION - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	SHAMROCK - NORTH FLORIDA REGION	DIST - UNATTENDED	12.00	4.00	
9	SOPCHOPPY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	ST. GEORGE ISLAND - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	ST. MARKS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	SUTTERS CREEK - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	SUWANNEE - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
14	TRENTON - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	UNIVERSITY OF FLORIDA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	23.00	
16	WAUKEENAH - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
17	WHITE SPRINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
18	WILLISTON - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	WILLISTON TOWN - NORTH FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
20					
21	ADAMS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	ALAFAYA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23	ALTAMONTE SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
24	ALTAMONTE SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	APOPKA SOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	BARBERVILLE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	BAY RIDGE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
28	BELLEVIEW - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
29	BEVERLY HILLS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
30	CASSADAGA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
31	CASSELBERRY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
32	CIRCLE SQUARE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	CITRUS HILL - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
34	CLARCONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	CLERMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	COLEMAN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	CRYSTAL RIVER NORTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
38	CRYSTAL RIVER SOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
39	DELAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
40	PINE RIDGE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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	2					1
40	2					2
20	1					3
100	1					4
20	1					5
200	2					6
19	1	1				7
2	1	1				8
9	1	1				9
20	1					10
13	1	1				11
19	2					12
20	1					13
13	1	1				14
90	3					15
9	1					16
2	1	1				17
13	1	1				18
9	1					19
						20
20	1					21
60	2					22
200	1					23
100	2					24
90	3					25
40	2					26
40	2					27
100	2					28
60	2					29
60	2					30
130	3					31
19	2					32
50	2					33
90	3					34
60	2					35
29	2					36
19	1	1				37
9	1	1				38
100	2					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	12/31/2007	End of 2007/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	DELAND EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
2	DELTONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	
3	DELTONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
4	DELTONA EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
5	DOUGLAS AVENUE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	DUNNELLON TOWN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	EAGLENEST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	EATONVILLE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
9	ECON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
10	EUSTIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	EUSTIS SOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
12	FERN PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
13	GROVELAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	116.00	
15	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
16	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
17	HOMOSASSA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
18	HOWEY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	INGLIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	67.00	
20	INGLIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	INVERNESS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	7.00
22	INVERNESS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23	KELLER ROAD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	KELLY PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	LADY LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	LAKE ALOMA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	LAKE EMMA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
28	LAKE HELEN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
29	LAKE WEIR - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
30	LEBANON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	12.00	
31	LIBSON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
32	LOCKHART - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
33	LOCKWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	MAITLAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	MARICAMP - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	MARTIN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
38	MCINTOSH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
39	MINNEOLA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
40	MONTEVERDE - NORTH CENTRAL FL 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	12/31/2007	End of 2007/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.
90	3					1
75	1					2
120	3					3
60	2					4
60	2					5
40	2					6
19	2					7
90	3					8
100	2					9
60	2					10
63	2					11
30	1					12
40	2					13
250	1					14
250	1					15
19	2					16
20	1					17
13	1	1				18
100	1					19
9	1					20
160	2					21
60	2					22
60	2					23
9	1					24
29	2					25
100	2					26
100	2					27
55	2					28
19	2					29
10	1	1				30
40	2					31
100	2					32
30	1					33
40	2					34
90	3					35
19	2					36
20	1					37
9	1					38
20	1					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) 12/31/2007	Year/Period of Report End of 2007/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	MOUNT DORA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
2	MYRTLE LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
3	NORTH LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
4	NORTH LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
5	OCOEE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	OKAHUMPKA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	ORANGE BLOSSOM - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	ORANGE CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	115.00	14.00
9	ORANGE CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
10	OVIEDO - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	PIEDMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
12	PIEDMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	PLYMOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	PLYMOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
15	RAINBOW SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	REDDICK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	SANTOS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	SILVER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
19	SILVER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	SILVER SPRINGS SHORES-NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	SPRING LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	TROPIC TERRACE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
23	TURNER PLANT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	7.00
24	TURNER PLANT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	TWIN COUNTY RANCH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	110.00	13.00	
26	TWIN COUNTY RANCH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
27	UNIV OF CENTRAL FL - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
28	UNIV OF CNTL FL NORTH-NORTH CNTL FL REGION	DIST - UNATTENDED	67.00	13.00	
29	UMATILLA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
30	WEIRSDALE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	WEKIVA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
32	WELCH ROAD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
33	WEST CHAPMAN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	WILDWOOD CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	WINTER GARDEN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	WINTER GARDEN CITRUS-NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	WINTER GARDEN CITRUS#2-NORTH CENTRAL FL REGION	DIST - UNATTENDED	12.00		
38	WINTER GARDEN CITRUS#2-NORTH CENTRAL FL REGION	DIST - UNATTENDED	12.00		
39	WINTER PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
40	WINTER PARK EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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
100	2					2
250	1					3
100	2					4
90	3					5
40	2					6
40	2					7
250	1					8
60	2					9
90	3					10
250	1					11
100	2					12
13	1	1				13
9	1					14
20	2					15
22	2					16
13	1					17
250	1					18
20	1					19
40	2					20
90	3					21
40	2					22
160	2					23
40	2					24
13	1	1				25
9	1					26
60	2					27
60	2					28
40	2					29
19	2					30
100	2					31
100	2					32
60	2					33
25	1					34
100	2					35
9	1	1				36
1	1					37
5	4					38
120	4					39
500	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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	WINTER PARK EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
2	WINTER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
3	WINTER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	WOODSMERE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
5	WOODSMERE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	ZELLWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	ZUBER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8					
9	AGRICOLA #4 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	ARBUCKLE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
12	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	67.00	12.00
13	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	AVON PARK NORTH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
15	BABSON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	BARNUM CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	BAY HILL - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	BITHLO - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	BOGGY MARSH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	BONNET CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	CABBAGE ISLAND - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	CANOE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	4.00
23	CELEBRATION - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	CENTRAL PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	CHAMPIONS GATE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
26	CITRUSVILLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	CLEAR SPRINGS EAST - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
28	COLONIAL - SOUTH CENTRAL FL REGION	DIST-UNATTENDED	69.00	13.00	
29	CONWAY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
30	COUNTRY OAKS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	CROOKED LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
32	CURRY FORD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
33	CYPRESSWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	DACO - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	DAVENPORT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	DESOTO CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	DINNER LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
38	DUNDEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
39	EAST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
40	EAST ORANGE - SOUTH CENTRAL FL 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	12/31/2007	End of 2007/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.
100	2					1
250	1					2
90	3					3
250	1					4
40	2					5
40	2					6
29	2					7
						8
9	1					9
8	1					10
200	1					11
150	1					12
40	2					13
40	2					14
20	1					15
60	2					16
90	3					17
50	2					18
100	2					19
60	2					20
60	2					21
30	1					22
60	2					23
90	3					24
20	1					25
20	1					26
20	1					27
30	1					28
40	2					29
40	2					30
10	1					31
50	1					32
40	2					33
13	1					34
20	1					35
19	2					36
75	2					37
20	1					38
19	2					39
120	3					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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	FISHEATING CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	8.00
2	FISHEATING CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	8.00
4	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	110.00	14.00
5	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
6	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	FOUR CORNERS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	FROSTPROOF - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
9	HAINES CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	HEMPLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	HOLOPAW - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	25.00	
12	HORSE CREEK #2 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
13	HUNTERS CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	INTERNATIONAL DRIVE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
15	ISLEWORTH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	LAKE BRYAN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
17	LAKE BRYAN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	LAKE LUNTZ - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
19	LAKE MARION - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	LAKE OF THE HILLS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	LAKE PLACID - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23	LAKE WILSON - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	LAKEWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	LEISURE LAKES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	LITTLE PAYNE CREEK#1-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
27	LITTLE PAYNE CREEK#2-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
28	MAGNOLIA RANCH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
29	MAGNOLIA RANCH TEMP - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
30	MARLEY ROAD - SOUTH CENTRAL FL REGION	DIST- UNATTENDED	69.00	13.00	
31	MEADOWS WOODS SOUTH-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
32	MEADOWS WOODS SOUTH-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	MIDWAY TEMP - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
34	MULBERRY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	4.00	
35	NARCOOSEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	NORALYN #1 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	12.00	
37	NORALYN #2 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
38	ODESSA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
39	ORANGEWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
40	PARKWAY - SOUTH CENTRAL FL 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) 12/31/2007	Year/Period of Report End of 2007/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.
150	1					1
9	1					2
60	1					3
150	1					4
200	1					5
9	1					6
60	2					7
50	2					8
80	2					9
60	2					10
25	2					11
9	1					12
110	3					13
100	2					14
19	2					15
500	2					16
90	3					17
100	2					18
20	1					19
20	1					20
40	2					21
60	2					22
40	2					23
55	2					24
9	1					25
13	1					26
13	1					27
60	2					28
20	1					29
30	1					30
200	1					31
60	2					32
9	1					33
6	1	1				34
90	3					35
9	3	1				36
9	1	1				37
30	1					38
100	2					39
60	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	12/31/2007	End of 2007/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	PEMBROKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	12.00	
2	PINECASTLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	POINCIANA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	REEDY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	RIO PINAR - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
6	RIO PINAR - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	SAND LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	SAND MOUNTAIN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
9	SEBRING EAST - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	SHINGLE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	SKY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
12	SKY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	SOUTH BARTOW - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	SOUTH FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	25.00	
15	SOUTH FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	4.00	
16	SUNFLOWER - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
17	SUN'N LAKES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	TAFT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	TAUNTON RD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	VINELAND - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	WAUCHULA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	WEST DAVENPORT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
23	WEST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
24	WEST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	WESTRIDGE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	WEWAHOOTEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	13.00	4.00	
27	WEWAHOOTEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
28	WHIDDEN CREEK #1 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
29	WINDERMERE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
30	WINDERMERE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31					
32	TOTAL DISTRIBUTION		35014.00	7608.00	360.00
33					
34	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
35	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
36	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	133.00	
37	BROOKSVILLE WEST - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
38	HIGGINS PLANT - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
39	HUDSON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
40	LAKE TARPON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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.
2	1	1				1
40	2					2
100	2					3
40	2					4
500	2					5
100	2					6
80	2					7
9	1	1				8
20	1					9
60	2					10
250	1					11
90	3					12
9	1					13
19	1					14
45	2					15
30	1					16
40	2					17
60	2					18
20	1					19
60	2					20
19	2					21
19	2					22
250	1					23
13	1	1				24
50	1					25
9	1	1				26
13	1	1				27
20	1					28
200	1					29
40	2					30
						31
25361	578	49				32
						33
750	1					34
250	1					35
250	1					36
250	1					37
250	1					38
500	2					39
1500	2	1				40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2007	Year/Period of Report End of 2007/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					
2	DRIFTON - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	5.00
3	GUMBAY - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
4	HAVANA - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
5	IDYLWILD - NORTH FLORIDA REGION	TRANS - UNATTENDED	138.00	67.00	12.00
6	QUINCY - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	4.00
7	SUWANNEE 230 KV - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
8	TALLAHASSEE - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	8.00
9	WILCOX - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
10	LIBERTY - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	
11	ANDERSEN - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	14.00
12	BARBERVILLE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	115.00	66.00	33.00
13	CAMP LAKE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	15.00
14	CENTRAL FLORIDA - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	512.00	230.00	14.00
15	CENTRAL FLORIDA - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
16	CLERMONT EAST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	14.00
17	CRYSTAL RIVER EAST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	116.00	
18	DELAND WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
19	DELAND WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	115.00	67.00	15.00
20	HAINES CREEK - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
21	MARTIN WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
22	ROSS PRAIRIE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	69.00	
23	SORRENTO - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
24					
25	AVALON - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	69.00	
26	BARCOLA - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
27	GRIFFIN - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	115.00	13.00
28	INTERCESSION CITY - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
29	KATHLEEN - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	512.00	230.00	14.00
30	NORTH BARTOW - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
31	VANDOLAH - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	23.00
32					
33	TOTAL TRANSMISSION		8511.00	3480.00	240.00
34					
35					
36					
37					
38					
39					
40					

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.
						1
105	2					2
75	1					3
75	1					4
150	1					5
75	1					6
400	2					7
120	2					8
150	1					9
150	1					10
133	1					11
30	4	1				12
150	1					13
1500	2					14
450	2					15
250	1					16
250	1					17
200	1					18
125	1					19
250	1					20
200	1					21
150	1					22
250	1					23
						24
250	1					25
150	1					26
250	1					27
250	1					28
750	1					29
150	1					30
400	2					31
						32
11188	47	2				33
						34
						35
						36
						37
						38
						39
						40

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.: 14 Column: h

Spare transformers present at each substation are reported, but not included in the capacity rating of the station.

Florida Public Service Commission

Diversification Report

Progress Energy Florida Inc.

December 31, 2007

Progress Energy

SIGNATURE PAGE

I certify that I am the responsible accounting officer of
PROGRESS ENERGY FLORIDA, INC.
that I have examined the following report; that to the best of my knowledge, information, and belief, all statements of fact contained in the said report are true and the said report is a correct statement of the business and affairs of the above-named respondent in respect to each and every matter set forth therein during the period from January 1, 2007 to December 31, 2007, inclusive.

I also certify that all affiliated transfer prices and affiliated cost allocations were determined consistent with the methods reported to this Commission on the appropriate forms included in this report.

I am aware that Section 837.06, Florida Statutes, provides:

Whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree, punishable as provided in s. 775.082, s. 775.083, or s. 775.084.

4-29-08
Date

Signature

Will A. Garrett
Name

Controller - Progress Energy Florida
Title

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2007

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
			Junior Achievement of West Central Florida	
Will A. Garrett	Controller	None		
William D. Johnson	Chairman and CEO	Board Member	Daugherty Endowment Fund	Raleigh, NC
		Board Member	Rex Hospital	Raleigh, NC
		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	
		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	Director	Board Member	Pinellas Association for Retarded Citizens	
		Member	Univeristy of Florida Engineering Advisory Council	
Jeff Lyash	President	Council Member	Florida High Tech Corridor	
		Council Member	Metro Orlando Economic Development Commission	Orlando, FL
		Director	Enterprise Florida, Inc.	Orlando, FL
		Director	Florida Chamber of Commerce	
		Director	SunTrust Bank	Tampa, FL
		Director	The Southeaster Electric Exchange	
		Director, Member, Chair	The Florida Orchestra	Tampa, FL
		Director	Florida Reliability Coordinating Council (FRCC)	Tampa, FL
		Director	Pinellas Education Foundation	Largo, FL
		Director	Tampa Bay Partnership	Tampa, FL
		Executive Committee	Florida Electric Power Coordinating Group (FCG)	Tampa, FL
		Member	The Florida Council of 100	Tampa, FL
		Trustees	Florida Chamber of Commerce Foundation, Inc.	
		Board Member	The Museum of Fine Arts	St. Petersburg, FL

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2007

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	
John R. McArthur	Director, Senior Vice President	Board of Directors	Business - Industry Political Action Committee (BIPAC)	Raleigh, NC
		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	Global Transpark Foundation, Inc.	Kinston, NC
		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 Real Estate Holdings, Inc.	
		Board of Directors	Progress Telecommunications Corporation	
		Board of Directors	Progress Ventures, Inc.	
		Board of Directors	PV Holdings, Inc.	
		Board of Directors	Strategic Resource Solutions	
		Chair	Teach for America Eastern NC Advisory Board	Raleigh & Rocky Mt., NC
		Chairman	N.C. Education Lottery Commission	Raleigh, NC
Robert B. McGehee	Former Chairman and CEO *(Deceased October 9, 2007)*	Board Member	WANO, Atlanta Center	Atlanta, GA
		Board Member	The Florida Council of 100	Tampa, FL
		CEO	Florida Progress Corporation	
		Chairman/Director	Progress Capital Holdings, Inc.	
		Director	PV Holdings, Inc.	
		Director and President	Progress Energy Foundation, Inc.	
		Director/Chairman	Progress Energy Ventures, Inc.	
		Director/Chairman	Progress Fuels Corporation	
		Director/Chairman	Progress Real Estate Holdings, Inc.	
		Executive Committee	Progress Energy, Inc.	
		Manager	Progress Energy Service Company, LLC	
		Vice Chairman	Atomic Energy Committee of the Public Utility Communications and Transportation Law Section of the American Bar Association	
Mark Mulhern	Senior VP Finance	Director	Dulcimer Land Company, Inc.	
		President	Kanawha River Terminals, Inc.	
		President	Kentucky May Coal Company, Inc.	
		President	Marigold Dock, Inc.	
		Board Member	Microcell	
		President	Powell Mountain Coal Company, Inc.	
		President	Progress Fuels Corporation	
		President	Progress Synfuel Holdings, Inc.	
		President	Progress Ventures, Inc.	
		President	PV Holdings, Inc.	
James Scarola	Sr. Vice President	Board Member	Parr Shoals Reactor (Carolina/Virginia Corp Board)	

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2007

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	
Frank A. Schiller	General Counsel	Director	Capitan Corporation	
		Director	Carofund, Inc.	
		Director	Dulcimer Land Company, Inc.	
		Director	Florida Progress Funding Corporation	
		Director	Kanawha River Terminals, Inc.	
		Director	Kentucky May Coal Company, Inc.	
		Director	Marigold Dock, Inc.	
		Director	PEC Fort Drum, Inc.	
		Director	PIH Tax Credit Fund, III. IV, V	
		Director	PIH, Inc.	
		Director	Powell Mountain Coal Company, Inc.	
		Director	Progress Energy Envirotree, Inc.	
		Director	Progress Materials, Inc.	
		Director	Progress Provisional Holdings, Inc.	
		Director	Progress Reinsurance Company, Ltd.	
		Director	Progress Synfuel Holdings, Inc.	
		Director	Progress Telecommunications	
		Director	Stratetic Resource Solutions, Inc.	
		Director	West Drum Holdings Corporation	
Peter M. Scott III	Director, Executive Vice President and Chief Financial Officer	Board Member	North Carolina Museum of Art Foundation Board	Raleigh, NC
		Board Member	Nuclear Electric Insurance Limited (NEIL)	Wilmington, DE
		Board Member	RTI International	Raleigh, NC
		Board Member	UNC Board of Visitors	
		Board Member	UNC Kenan-Flagler Business School's Board of Visitors	
		Board of Governors	Capital City Club	Raleigh, NC
		CFO	Florida Power Corporation	
		CFO	Progress Energy Service Company, LLC	
		Director	Progress Fuels Corporation	
		Director	Progress Ventures Holdings, Inc.	
		Director	Progress Ventures, Inc.	
		Director/President	Capitan Corporation	
		Director/President	Carofund, Inc.	
		Director/President	Progress Capital Holdings, Inc.	
		Director/Treasurer	Progress Energy Foundation, Inc.	
		Vice President	Progress Real Estate Holdings, Inc.	
Paula Sims	Sr. Vice President	Board Member	Center for Energy and Economic Development	
Jeffrey M. Stone	Chief Accounting Officer	None		
Thomas R. Sullivan	Vice President, Treasurer	None		
Lloyd Yates	President and CEO, PGN Carolinas	Board Member	Association of Edison Illuminating Companies	
		Chairman	Triangle Urban League	
		Board Member	American Heart Association	
		Board Member	Greater Raleigh Visitors Bureau	
		Board Member	High Five Board	

Business Contracts with Officers, Directors and Affiliates

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2007

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
Jeff Lyash	Tampa Bay Partnership, Inc. Tampa, FL	5,000	Donation
Jeff Lyash	Florida Chamber of Commerce Tallahassee, Florida	10,000	Dues
Jeff Lyash	Pinellas County Education Foundation Largo, Florida	10,000	Donation
Jeff Lyash	The Florida Orchestra Tampa, Florida	10,000	Donation
Jeff Lyash	Florida Reliability Coordinating Group Tampa, Florida	7,143	Dues

Reconciliation of Gross Operating Revenues
Annual Report versus Regulatory Assessment Fee Return

Company: ***Progress Energy Florida Inc.*** ***For the Year Ended December 31, 2007***

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)	$ 4,138,377,879	$ 35,243,647	$ 4,103,134,232	$ 4,138,377,878	$ 35,243,647	$ 4,103,134,232	$ 0
2	Sales for Resale (447)	435,681,011	435,889,941	(208,930)	435,681,011	435,889,941	(208,930)	(0)
3	Total Sales of Electricity	4,574,058,890	471,133,589	4,102,925,302	4,574,058,890	471,133,589	4,102,925,302	(0)
4	Provision for Rate Refunds (449.1)	(1,675,074)	(1,675,074)	(0)	(1,675,074)	(1,675,074)	-	(0)
5	Total Net Sales of Electricity	4,572,383,816	469,458,515	4,102,925,302	4,572,383,816	469,458,515	4,102,925,302	(0)
6	Total Other Operating Revenues (450-456)	120,139,516	43,410,542	76,728,974	121,502,117	43,410,542	78,091,576	(1,362,601) (1)
7	Other (Specify)							
8								
9								
10	**Total Gross Operating Revenues**	$ 4,692,523,332	$ 512,869,056	$ 4,179,654,276	$ 4,693,885,933	$ 512,869,056	$ 4,181,016,878	$ (1,362,602)

Notes: (1) Difference reflects intercompany revenues that should have been considered part of operating revenues derived from intrastate business last year.

Analysis of Diversification Activity
Changes in Corporate Structure

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2007

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)
1/1/2007	Progress Energy Service Company (PESC) was moved under Progress Ventures, Inc.
3/2/2007	Progress Energy Service Co. acquired NewCraft, LLC from a third party.
3/22/2007	AAV Synfuel, LLC was formed as a single-member LLC under Progress Fuels Corp.
3/30/2007	Progress Telecom Holding, Limitada and Progress Telecom Do Brazil, Limitada (subsidiaries of PT Holding Company, LLC) were dissolved.
3/30/2007	Ceredo Synfuel LLC was sold to a third party.
6/11/2007	Progress Ventures, Inc. and Progress Genco Ventures, LLC sold their membership interests in the following entities: Effingham County Power, LLC; MPC Generating, LLC; Walton County Power, LLC; and Washington County Power, LLC.
6/29/2007	Progress Energy Carolinas' ownership interest in Microcell Corporation became 1.986%.
6/29/2007	PEC and PEF each became 12.5% members of APOG, LLC, a newly-formed LLC owned by various Southeastern utilities.
7/27/2007	3079936 Nova Scotia Company, a subsidiary of Progress Fuels Corp., was dissolved.
8/10/2007	Progress Telecom International, LLC (a subsidiary of PT Holding Company, LLC) was dissolved.
8/21/2007	Progress Telecom Virginia, LLC (a subsidiary of PT Holding Company, LLC) was dissolved.
8/31/2007	NewCraft, LLC, a wholly-owned subsidiary of Progress Energy Service Company, LLC, was dissolved.
9/14/2007	Westpower-Fort Drum, LP was dissolved.
10/8/2007	Westmoreland-Fort Drum, LP was dissolved.
10/25/2007	Progress Real Estate Holdings, Inc. merged into Progress Energy Service Co, LLC.
10/31/2007	Progress Genco Ventures, LLC (a subsidiary of Progress Ventures, Inc.) was dissolved.
11/1/2007	Progress Materials, Inc. was converted into a single-member LLC known as PMI Target, LLC.
11/5/2007	Progress Materials, LLC was sold to a third party.
12/31/2007	West Drum Holdings Corporation was dissolved.
12/31/2007	PEC Fort Drum, Inc. was dissolved.
12/31/2007	Progress Provisional Holdings, Inc. was dissolved.

Analysis of Diversification Activity
New or Amended Contracts with Affiliated Companies

Company: ***Progress Energy Florida Inc.***

For the Year Ended December 31, 2007

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)
Progress Energy Service Company (PESC)	Amendment to Article IV of the Utility Service Agreement executed January 1, 2001 between Progress Energy Florida (PEF) and Progress Energy Service Company (PESC) to include personal computers that PEF will provide to PESC. Effective date: October 18, 2007 Duration: open ended Price: higher of cost or market

Analysis of Diversification Activity
Individual Affiliated Transactions in Excess of $500,000

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2007

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)
Progress Energy Service Company LLC	Recurring monthly Service Company functions and services. See Page 457 for description.	$ 179,700,952
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Recurring monthly shared utility functions and services. See page 457 for description.	51,355,310
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Non-recurring nuclear refueling outage assistance	2,179,245
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Recurring monthly Service Company functions and services. See Page 457 for description.	10,170,009

Analysis of Diversification Activity
Summary of Affiliated Transfers and Cost Allocations

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2007

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)	Shared utility functions, technical services support, operations support, combustion turbine operations & maintenance, core environmental services; Transmission & Distribution support, distribution design; Customer service performance solutions, answer customer calls; Nuclear services and business operations oversight, nuclear security support,management, regulatory, engineering, contract and material support; Energy Delivery management & oversight, distribution design; Power Operations operations support; Residential support services	Utility Service Agreement 1/1/2001	S	1460001	10,170,009
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Shared utility functions and services such as nonreg transmission maintenance service, ECCR energy efficiency support, retail energy sales support, premier power support, PPS managed services support, transmission/distribution support, ED management/ovrsight, contract services, customer service management, performance solutions, nuclear management, nuclear IT, nuclear analytical services, common nuclear services, nuclear security support, regulatory assessment/oversight, engineering programs, materials and contract support, coal procurement and transportation, power ops management and finance, techical services support, CT ops/maintenance RCO purchased power contract support, RCO joint owner contract support, RCOoperational support, RCO wholesale term contract support, RCO gas and oil procurement, regulated lighting support, exterio lighting support, fuel forecasting and regulatory support.	Utility Service Agreement 1/1/2001	P	2340001	53,534,555
Progress Energy Ventures	Technical, Support & Training Svcs, CT Operations & Maintenance support, CT Performance Improvement support	Utility Service Agreement 11/1/2002	S	1460020	169,194
Effingham County Power, LLC[1]	Technical Support for CT Operations	Utility Service Agreement 11/1/2002	S	1460025	6,749
MPC Generating, LLC[1]	Technical Support for CT Operations	Utility Service Agreement 11/1/2002	S	1460032	5,461

Analysis of Diversification Activity
Summary of Affiliated Transfers and Cost Allocations

Company:* *Progress Energy Florida Inc.

For the Year Ended December 31, 2007

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.

				Total Charge for Year	
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)	Account Number (e)	Dollar Amount (f)
Walton County Power, LLC[1]	Technical Support for CT Operations, Line maintenance support	Utility Service Agreement 11/1/2002	S	1460033	6,452
Washington County Power, LLC[1]	Technical Services Support, CT Ops/Maint support	Utility Service Agreement 11/1/2002	S	1460034	15,286
Progress Fuels Corporation	Fly Ash sales, Potable & Process Water sales	Ash Management Contract Extensions 9/1/1995 and 9/2/2005	S	1460061	259,979
Progress Fuels Corporation	Fly Ash storage	Ash Management Contract Extensions 9/1/1995 and 9/2/2005	P	2340061	348,313
PT Holding Company LLC	Network Services, Land Lease, Revenue Sharing	Master Service and Wireless Attachment Agreements - 12/19/2003	S	1460071	2,945,232
Progress Energy Service Company LLC	Labor and associated expenses, materials	Utility Service Agreement 1/1/2001	S	1460098	3,943,464
Progress Energy Service Company LLC	Executive Management, Legal, IT, Accounting Svcs, Audit Svcs, Planning, Telecom, Public Affairs, Human Resources, Corp Communications, Security, Supply Chain Svcs, Real Estate Svcs, Tax Svcs, Risk Mgmt, Environmental Svcs, Health & Safety Svcs, Treasury, Risk Mgmt, Disbursement Svcs, Other Shared Corp Svcs. Excludes convenience payments and pay agent transactions.	Utility Service Agreement 12/1/2000	P	2340098	179,700,952

[1] Entity sold to an unrelated third party on 6/11/07. Transactions reported above represent goods and services provided from 1/1/07 through 6/11/07.

Analysis of Diversification Activity
Assets or Rights Purchased from or Sold to Affiliates

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2007

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:							
None							
Total		$ -	-	$ -	$ -	$ -	
Sales to Affiliates:		$	$	$	$	**Sales Price**	
Progress Energy Service Company	Computers	124,021.48		124,021.48	124,021.48	124,021.48	
Total						**124,021.48**	

Analysis of Diversification Activity
Non-Tariffed Services and Products Provided by the Utility
Company: Florida Power Corporation
For the Year Ended December 31, 2007

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	4170000	Non-Regulated
Turnkey Solutions	4170000	Non-Regulated
Power Quality Services	4170000	Non-Regulated
Homewire	4170000	Non-Regulated
All-Connect	4170000	Non-Regulated
Lighting	4170000	Non-Regulated
Infrared Scanning Services	4170000	Non-Regulated
High Voltage Services	4170000	Non-Regulated
Distribution Services	4170000	Non-Regulated
Vegetation Services	4170000	Non-Regulated
Metering Services	4170000	Non-Regulated
Transformer Services	4170000	Non-Regulated
Material Solutions	4170000	Non-Regulated
Joint Trenching	4170000	Non-Regulated
General System Planning	4170000	Non-Regulated
Transmission Construction & Maintenance	4170000	Non-Regulated
Substation Design, Construction & Maintenance	4170000	Non-Regulated
System Protection & Control, Fiber Optic & Meter Services	4170000	Non-Regulated
Land Management	4170000	Non-Regulated
Wireless Transmission Tower Attachments	4210708	Non-Regulated

Nonutility Property (Account 121)

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2007

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	527,365		527,365
Not Previously Devoted to Public Service			
Land - Volusia County, Florida (1)	1,636,204	-13,813	1,622,391
Equipment - Meters System (Florida) (2)	5,423,549		5,423,549
Equipment - Walk of Fame, St. Pete, FL	1,380,193		1,380,193
Other	325,828		325,828
Generators on Customer premises	732,987		732,987
Communication Equipment (3)	0		0
Totals	$ 10,338,328	$ (13,813)	$ 10,324,515

Number of Electric Department Employees

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2007

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)	**10/28/2007**
2. Total Regular Full-Time Employees	**3979**
3. Total Part-Time and Temporary Employees	**308**
4. Total Employees	**4287**

Details

Regular Part Time:	6
Temp Full Time:	300
Temp Part Time:	2
Total:	**308**

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Company: Florida Power Corporation
For the Year Ended December 31, 2007

Report the information specified below, in the order given, for the respective income deduction and interest charges account. Provide a subheading for each account and a total for each account. Additional columns may be added if deemed appropriate with

(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 then 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 Debit / (Credit)
Account 426 - Miscellaneous Income Deductions	
Donations	
Civic & Community Organizations	489,087.69
Cultural & Arts Organizations	547,825.08
Economic Development	518,631.75
Education Related Contributions	1,535,537.57
Environment	125,671.30
Health & Human Services Contributions	911,332.26
Other	272,197.23
Subtotal Accounts 4261014, 426180T, 4261BUD	4,400,282.88
Investment in Company Owned Life Insurance	(2,507,651.00)
Subtotal Accounts 4262016, 4262041	(2,507,651.00)
Penalties	2,111,224.86
Subtotal Account 4263001	2,111,224.86
Certain Civic, Political & Related Activities	4,097,876.28
Subtotal Accounts 4264100, 4264200, 4264300	4,097,876.28
Other Deductions	1,162,300.87
Subtotal Account 4265001	1,162,300.87
Total Miscellaneous Income Deductions - Account 426	9,264,033.89
Account 430 - Interest on Debt to Associated Companies	
Money Pool (Avg Rate 5.49%)	2,199,542.83
Total Interest on Debt to Associated Companies - Account 430	2,199,542.83
Account 431 - Other Interest Expense	
Commitment Fees (4310010)	473,767.11
Other Interest Expense (4310001, 4310011)	598,938.20
Customer Deposits - Rate 6 to 7% per annum	10,601,213.47
Interest related to OPC Petition Customer Refund- Rate 4.87%	1,755,990.00
Interest related to Dixie Fuels Surcharge - Rate 30.24%	2,079,593.64
Interest related to Projected Tax Deficiency on various audit issues - Rate 6.7%	2,796,676.52
Total Other Interest Expense - Account 431	18,306,178.94

Budgeted and Actual In-Service Costs of Nuclear Power Plant

Company: *Progress Energy - Florida* *[Section (8)(f)]*

For the Year Ended December 31, 2007

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): 2007**	**Remaining Budgeted Costs to Complete Plant:**	**Total Estimated Cost of Plant**	**Estimated Cost provided in the Petition for Need Determination (1) (or revised estimate as necessary)**
Licensing/Permits/Authorizations/Legal	$0	$0	0	$0
Site/Site Preparation	0	$0	0	0
Related Facilities - POD	70,000	$42,608,600	42,678,600	49,450,000
Generation Plant	40,750,589	280,843,299	321,593,888	287,500,000
Transmission Facilities	0	$0	0	102,350,000
Total	$40,820,589	$323,451,899	$364,272,488	$439,300,000

1) 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.

2) All of these costs exclude AFUDC.

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