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EI801-06-AR

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

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)

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DIVISION OF
ECONOMIC REGULATION

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 2006/Q4

FERC FORM No.1/3-Q (REV. 02-04)

Deloitte

Deloitte & Touche LLP
Certified Public Accountants
Suite 400
200 South Biscayne Boulevard
Miami, FL 33131-2310
USA

Tel: +1 305 372 3100
Fax: +1 305 372 3106
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

Florida Power & Light Company
Miami, Florida

We have audited the balance sheets of FPL-New England Division (a division of Florida Power & Light Company) (the "Division") as of December 31, 2006 and 2005, and the related statements of income and changes in division equity for the years then ended, included on pages 123.37 through 123.40 of the Florida Power & Light Company's 2006 Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Division's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 Division'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 audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of FPL-New England Division at December 31, 2006 and 2005, and the results of its operations for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the financial statements, the financial statements have been prepared from the separate records maintained by the Division and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Division had been operated as an unaffiliated entity.

Deloitte + Touche LLP

April 27, 2007

INSTRUCTIONS FOR FILING FERC FORMS 1, 1-F and 3-Q

GENERAL INFORMATION

I Purpose

Form 1 is an annual regulatory support requirement under 18 CFR 141.1 for Major public utilities, licensees and others. Form 1-F is an annual regulatory support requirement under 18 CFR 141.2 for Nonmajor public utilities, licensees and others. Form 3-Q is a quarterly regulatory support requirement which supplements Forms 1 and 1-F under 18 CFR 141.400. The reports are designed to collect financial and operational information from major and nonmajor electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a 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 CFR 101), must submit Form 1 as prescribed in 18 CFR Part 141.1. Each Nonmajor electric utility, licensee or other must submit Form 1-F as prescribed in 18 CFR Part 141.2. Each Major and Nonmajor electric utility licensee or other, must submit Form 3-Q as prescribed in 18 CFR Part 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).

Nonmajor means having in each of the three `previous calendar years, total annual sales of 10,000 megawatt hours or more

III. What and Where to Submit
(a) Submit Forms 1, 1-F and 3-Q electronically through the Form 1/3-Q Submission Software. Retain one copy of each report for your files.
(b) Respondents may submit the Corporate Officer Certification electronically, or file/mail an original signed Corporate Officer Certification to:

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

(c) Submit, immediately upon publication, four (4) copies of the latest annual report to stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. (Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 1, Page 4, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared.) Mail these reports to the address in III(c) above.

(d) For the Annual CPA certification, submit with the original submission, or within 30 days after the filing date for Form 1, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):

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

(ii) 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 CFR 158.10-158.12 for specific qualifications.)

Reference	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

Insert the letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the address indicated at III (b). Use the following form for the letter or report 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.

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

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from: Public Reference and Files Maintenance Branch Federal Energy Regulatory Commission 888 First Street, NE. Room 2A ED-12.2 Washington, DC 20426 (202).502-8371

IV. When to Submit:

Submit Form 1 according to the filing dates contained in section 18 CFR 141.1 of the Commission's regulations. Submit Form 1-F according to the filing dates contained in section 18 CFR 141.2 of the Commission's regulations. Submit Form 3-Q according to the filing dates contained in section 18 CFR 141.400 of the Commission's regulations.

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the 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.public reporting burden for the Form 1-F collection of information is estimated to average 112 hours per response. The public reporting burden for the 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: Mr. Michael Miller, ED-30); 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 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U. S. of A.

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 1/3-Q software and send a letter identifying which pages in the form have been revised. Send the letter to the Office of the Secretary.

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 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. Commision 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.

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 wit: ... (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 shalt 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 an 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 forebay reservoirs directly connected therewith, the primary line or Lines transmitting power therefrom 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 ;he 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 my prescribe the manner and form in which such reports shalt 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 *form or 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

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information of document required by the Commission in the course of an investigation conducted under this Act .... shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing .... "

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 2006/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)* 12/31/2006

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)* 04/18/2007
02 Title Chief Financial Officer		

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	12/31/2006	End of 2006/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)	122(a) - None
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 Debit	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	12/31/2006	End of 2006/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	
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	12/31/2006	End of 2006/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)
67	Substations	426-427	
68	Footnote Data	450	
	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	12/31/2006	End of 2006/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	12/31/2006	End of 2006/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	12/31/2006	End of 2006/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	1,539,535
2			
3	Executive Vice President	William D. Johnson	3,818,970
4			
5	Executive Vice President and Chief Financial Officer	Peter M. Scott III	4,197,537
6			
7	Senior Vice President and Chief Nuclear Officer	C.S. Hinnant	1,693,477
8			
9	Executive Vice President	Fred N. Day IV	1,717,523
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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) and the four most highly compensated officers other than the CEO for the year ended December 31, 2006. 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 2006 received by the five most highly compensated executives is determined in accordance with Item 402 of Regulation S-K as promulgated by the Securities and Exchange Commission. Progress Energy, Inc.'s (Progress Energy) executive officers serve as officers and/or directors of its various subsidiaries, including PEF. They have multiple responsibilities within and provide various services to Progress Energy and its subsidiaries. The compensation of Progress Energy's executive officers is designed to cover the full range of services they provide to Progress Energy and its subsidiaries. It is not the policy of Progress Energy to allocate compensation paid to its executive 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.

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.

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	12/31/2006	End of 2006/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	299 First Avenue North, St. Petersburg, FL 33701
2	Fred N. Day, IV, Executive Vice President	PO Box 1551, Raleigh, NC 27602
3	H. William Habermeyer, Jr., President and CEO	299 First Avenue North, St. Petersburg, FL 33701
4	William D. Johnson, Executive Vice President	PO Box 1551, Raleigh, NC 27602
5	Jeffrey J. Lyash, President and CEO	299 First Avenue North, St. Petersburg, FL 33701
6	John R. McArthur, Senior Vice President	PO Box 1551, Raleigh, NC 27602
7	Robert B. McGehee, Chairman	PO Box 1551, Raleigh, NC 27602
8	Peter M. Scott III, Executive Vice President and CFO	PO Box 1551, Raleigh, NC 27602
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Schedule Page: 105 Line No.: 1 Column: a

Elected to the Board effective June 15, 2006.

Schedule Page: 105 Line No.: 3 Column: a

Resigned from the Board effective May 31, 2006.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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, 2006 there were no important changes or additions to Franchise Rights.

During the quarter ended June 30, 2006 there were no important changes or additions to Franchise Rights.

During the quarter ended September 30, 2006 a new franchise was signed with the Town of Belleair, Florida. The previous franchise expired December of 2001. The new franchise has a 30-year term and 6% franchise fee. There were no other changes to franchise rights for the period.

During the quarter ended December 31, 2006, there were no changes to franchise rights for the period.

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

2. ACQUISITION OF OWNERSHIP IN OTHER COMPANIES

None

3. PURCHASE OR SALE OF AN OPERATING UNIT OR SYSTEM

None

4. IMPORTANT LEASEHOLDS

During the quarter ended December 31, 2006, Florida Power Corporation, d/b/a Progress Energy Florida, Inc., recorded a capital lease for a headquarters building in St. Petersburg that was completed in 2006. Florida Power Corporation entered into the agreement with PEF St. Petersburg FL, LLC, an unrelated party, in 2005. The lease commencement date was November 15, 2006 and expires on April 30, 2047. Payments under the agreement will total $103 million.

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

(a) During the quarter ended March 31, 2006, Florida Power Corporation did not issue nor redeem any commercial paper. The average daily weighted yield during the period was 4.754108.

(b) During the quarter ended June 30, 2006, Florida Power Corporation did not issue any commercial paper during the period and redeemed a total of $102,000,000. The average daily weighted yield during the period was 0.00.

(c) In connection with the sale of Progress Telecom, LLC on March 20, 2006, Florida Power Corporation provided indemnification of $8.4 million against costs associated with certain asset performances to Level 3 Communications, Inc.

(d) During the quarter ended September 30, 2006, Florida Power Corporation did not issue or redeem commercial paper during the period.

(e) During the quarter ended December 31, 2006, Florida Power Corporation did not issue or redeem commercial paper during the period.

(f) During the quarter ended December 31, 2006, Progress Energy Florida, Inc., selected a site in Levy County, Florida, to evaluate for possible future nuclear expansion. In connection with this site selection, Progress Energy, Inc. became the Guarantor in a Purchase and Sale Agreement for land in Levy County, Florida. Progress Energy guaranteed all payments required to be paid to seller including non-refundable deposits of $2.25 million; balance of purchase price at closing of $42.75 million; and deferred purchase payments of $4.5 million. Progress Energy also guaranteed complete compliance by Buyer of all terms and conditions of the agreement. The Buyer, acting on behalf of the Guarantor, at its sole discretion can determine not to purchase the land within 270 days from the effective date of the agreement.

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 November 27, 2006, all bargaining unit employees received a 3.2% 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 $3.5 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, 2006.

   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, 2006.

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, 2006.

See Part I, Item 3. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Annual Report on Form 10-K for the year-ended December 31, 2006.

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:

John S. Keenan, VP	Removed 1/9/2006
Billy R. Raley, VP	Removed 2/13/2006
David J. Maxon, VP	Elected 2/13/2006
Robert H. Bazemore, Jr., VP	Elected 3/15/2006

Officer Changes:

Paula J. Sims, VP	Removed 4/17/2006
Bill Habermeyer, CEO, President & Director	Removed 5/31/2006
Jeffrey J. Lyash, SVP	Removed 6/01/2006
Jeffrey A. Corbett, VP	Removed 6/15/2006
Paula J. Sims, SVP	Elected 4/17/2006
Charles M. Gates, VP	Elected 4/17/2006
Jeffrey J. Lyash, CEO & President	Elected 6/01/2006
Jeffrey A. Corbett, SVP & Director	Elected 6/15/2006

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	12/31/2006	End of 2006/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	9,232,902,903	8,789,013,695
3	Construction Work in Progress (107)	200-201	641,485,881	385,036,594
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,874,388,784	9,174,050,289
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,401,159,420	4,272,984,516
6	Net Utility Plant (Enter Total of line 4 less 5)		5,473,229,364	4,901,065,773
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	12,481,913	851,954
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		610,437	6,110,241
9	Nuclear Fuel Assemblies in Reactor (120.3)		99,097,726	98,974,953
10	Spent Nuclear Fuel (120.4)		0	49,800,071
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	53,780,714	80,246,740
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		58,409,362	75,490,479
14	Net Utility Plant (Enter Total of lines 6 and 13)		5,531,638,726	4,976,556,252
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)		10,338,328	19,431,391
19	(Less) Accum. Prov. for Depr. and Amort. (122)		3,815,226	10,976,032
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	0	1,750
24	Other Investments (124)		962,213	512,616
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		590,096,066	531,424,415
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	45,357,164
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		597,581,381	585,751,304
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		21,649,999	12,687,600
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	203,386,579
39	Notes Receivable (141)		74,067	1,341,415
40	Customer Accounts Receivable (142)		274,738,966	252,584,609
41	Other Accounts Receivable (143)		18,877,119	24,500,384
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		8,139,226	5,870,614
43	Notes Receivable from Associated Companies (145)		0	151,320
44	Accounts Receivable from Assoc. Companies (146)		11,226,533	11,231,843
45	Fuel Stock (151)	227	239,606,898	135,760,761
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	188,558,542	157,005,210
49	Merchandise (155)	227	550,736	259,681
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	1,942,701	9,611,855

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	12/31/2006	End of 2006/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		0	0
54	Stores Expense Undistributed (163)	227	5,825,542	9,156,997
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)		128,350,988	167,032,023
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	39,807
60	Rents Receivable (172)		602,569	341,514
61	Accrued Utility Revenues (173)		54,880,718	59,473,456
62	Miscellaneous Current and Accrued Assets (174)		46,500,000	0
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)		2,114,653	122,409,306
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	45,357,165
67	Total Current and Accrued Assets (Lines 34 through 66)		987,360,805	1,115,746,581
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		19,655,889	22,222,655
70	Extraordinary Property Losses (182.1)	230	89,985,218	206,801,434
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	382,576,666	495,698,128
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,861,010	1,845,394
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	9,409,719	30,456,477
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)		27,021,114	29,188,802
82	Accumulated Deferred Income Taxes (190)	234	380,246,000	201,057,047
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		911,755,616	987,269,937
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		8,028,336,528	7,665,324,074

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	12/31/2006	end of 2006/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	745,926,367	742,267,894
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	1,588,449,439	1,497,932,244
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	3,524	0
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)	-1,535,018	-111,569
16	Total Proprietary Capital (lines 2 through 15)		2,720,777,442	2,628,021,699
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,870,865,000	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	690,500,006	738,800,005
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,907,913	6,194,270
24	Total Long-Term Debt (lines 18 through 23)		2,556,457,093	2,603,470,735
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		53,436,969	0
27	Accumulated Provision for Property Insurance (228.1)		4,553,836	5,566,000
28	Accumulated Provision for Injuries and Damages (228.2)		12,783,989	20,887,409
29	Accumulated Provision for Pensions and Benefits (228.3)		233,539,828	172,905,984
30	Accumulated Miscellaneous Operating Provisions (228.4)		133,724,942	90,340,527
31	Accumulated Provision for Rate Refunds (229)		2,007,207	2,407,430
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		35,875,035	6,104,892
34	Asset Retirement Obligations (230)		298,680,863	289,505,643
35	Total Other Noncurrent Liabilities (lines 26 through 34)		774,602,669	587,717,885
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	102,000,000
38	Accounts Payable (232)		276,543,387	222,804,792
39	Notes Payable to Associated Companies (233)		46,890,541	12,726,233
40	Accounts Payable to Associated Companies (234)		115,946,045	100,825,190
41	Customer Deposits (235)		167,609,006	148,479,965
42	Taxes Accrued (236)	262-263	-21,326,851	33,505,144
43	Interest Accrued (237)		37,754,584	41,703,816
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)		15,160,392	14,308,056
48	Miscellaneous Current and Accrued Liabilities (242)		57,117,522	52,367,493
49	Obligations Under Capital Leases-Current (243)		926,770	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		124,960,289	6,104,892
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		35,875,035	6,104,892
54	Total Current and Accrued Liabilities (lines 37 through 53)		785,706,650	728,720,689
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	23,386,508	29,796,508
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	26,638,691	86,617,498
60	Other Regulatory Liabilities (254)	278	380,687,566	379,294,484
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	6,186,000	5,190,000
63	Accum. Deferred Income Taxes-Other Property (282)		440,451,000	438,183,791
64	Accum. Deferred Income Taxes-Other (283)		313,442,909	178,310,785
65	Total Deferred Credits (lines 56 through 64)		1,190,792,674	1,117,393,066
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		8,028,336,528	7,665,324,074

FOOTNOTE DATA

Schedule Page: 112 Line No.: 59 Column:

The prior year end balance for Other Deferred Credits is $6,513,980 less than reported in 2005 due to the reclassification of Winter Park Stranded Costs.

Schedule Page: 112 Line No.: 60 Column:

The prior year end balance of the Other Regulatory Liabilities is $6,513,980 greater than reported in 2005 due to the reclassification of Winter Park Stranded Costs.

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	12/31/2006	End of 2006/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	4,559,906,728	3,964,002,346		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,733,541,096	2,878,528,030		
5	Maintenance Expenses (402)	320-323	151,274,324	166,182,532		
6	Depreciation Expense (403)	336-337	266,506,666	269,678,438		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	354,560	373,504		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	13,839,761	13,963,292		
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)		122,357,617	50,486,892		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		429,143,745	105,728,403		
13	(Less) Regulatory Credits (407.4)		114,809,864	276,814,367		
14	Taxes Other Than Income Taxes (408.1)	262-263	309,074,331	278,509,732		
15	Income Taxes - Federal (409.1)	262-263	203,726,041	154,744,964		
16	- Other (409.1)	262-263	33,701,977	26,045,841		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	243,555,011	174,734,869		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	285,230,725	228,392,144		
19	Investment Tax Credit Adj. - Net (411.4)	266	-6,410,000	-5,484,000		
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)		15,499,640	14,728,420		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,115,713,083	3,622,603,309		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		444,193,645	341,399,037		

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/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
4,559,906,728	3,964,002,346					2
						3
2,733,541,096	2,878,528,030					4
151,274,324	166,182,532					5
266,506,666	269,678,438					6
354,560	373,504					7
13,839,761	13,963,292					8
-411,097	-411,097					9
122,357,617	50,486,892					10
						11
429,143,745	105,728,403					12
114,809,864	276,814,367					13
309,074,331	278,509,732					14
203,726,041	154,744,964					15
33,701,977	26,045,841					16
243,555,011	174,734,869					17
285,230,725	228,392,144					18
-6,410,000	-5,484,000					19
						20
						21
						22
						23
15,499,640	14,728,420					24
4,115,713,083	3,622,603,309					25
444,193,645	341,399,037					26

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	12/31/2006	End of 2006/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)		444,193,645	341,399,037		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		24,612,681	18,984,259		
34	(Less) Expenses of Nonutility Operations (417.1)		19,533,596	13,696,210		
35	Nonoperating Rental Income (418)		-254,832	-364,108		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	3,524			
37	Interest and Dividend Income (419)		22,285,651	7,421,958		
38	Allowance for Other Funds Used During Construction (419.1)		16,834,794	13,228,664		
39	Miscellaneous Nonoperating Income (421)		539,382	332,370		
40	Gain on Disposition of Property (421.1)		2,247,038	25,554,411		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		46,734,642	51,461,344		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		128,506			
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	5,544,987	5,893,387		
46	Life Insurance (426.2)		-2,437,454	-2,123,063		
47	Penalties (426.3)			4,350		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		4,583,542	3,730,611		
49	Other Deductions (426.5)		1,111,780	3,692,583		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,931,361	11,197,868		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	159,173	170,279		
53	Income Taxes-Federal (409.2)	262-263	3,058,570	-8,768,324		
54	Income Taxes-Other (409.2)	262-263	763,420	-567,966		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-198,797	19,216,000		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	489,416	10,439,000		
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)		3,292,950	-389,011		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		34,510,331	40,652,487		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		140,476,010	120,453,244		
63	Amort. of Debt Disc. and Expense (428)		4,239,516	3,416,045		
64	Amortization of Loss on Reaquired Debt (428.1)		2,167,686	2,158,945		
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	1,483,069	3,215,111		
68	Other Interest Expense (431)	340	7,158,209	5,129,913		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		5,056,905	8,474,818		
70	Net Interest Charges (Total of lines 62 thru 69)		150,467,585	125,898,440		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		328,236,391	256,153,084		
72	Extraordinary Items					
73	Extraordinary Income (434)			3,743,818		
74	(Less) Extraordinary Deductions (435)			187,999		
75	Net Extraordinary Items (Total of line 73 less line 74)			3,555,819		
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)			3,555,819		
78	Net Income (Total of line 71 and 77)		328,236,391	259,708,903		

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	12/31/2006	End of 2006/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		1,497,932,244	1,239,735,201
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Unrealized tax benefit/expense		-1,553,420	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-1,553,420	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		328,232,867	259,708,903
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)		1,588,449,439	1,497,932,244
	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	12/31/2006	End of 2006/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)		1,588,449,439	1,497,932,244
	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)		3,524	
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		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	12/31/2006	End of 2006/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)	328,236,391	259,708,903
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	267,789,359	271,508,782
5	Amortization of Limited and Electric Plant, Nuclear Fuel, Load Mgmt	33,690,216	32,890,246
6	Amortization of Debt Premium, expense and loss on acquisition	4,380,183	3,707,016
7	Other: (Gain) Loss on sale of assets, Other Adjustments to Net Income	34,929,531	124,428,537
8	Deferred Income Taxes (Net)	-42,363,927	-44,880,275
9	Investment Tax Credit Adjustment (Net)	-6,410,000	-5,484,000
10	Net (Increase) Decrease in Receivables	-23,395,952	-66,178,429
11	Net (Increase) Decrease in Inventory	-134,500,051	-35,879,902
12	Net (Increase) Decrease in Allowances Inventory	7,670,904	639,822
13	Net Increase (Decrease) in Payables and Accrued Expenses	-16,425,496	72,517,361
14	Net (Increase) Decrease in Other Regulatory Assets	467,615,731	-155,804,627
15	Net Increase (Decrease) in Other Regulatory Liabilities	70,661,106	-27,415,354
16	(Less) Allowance for Other Funds Used During Construction	16,834,794	13,228,664
17	(Less) Undistributed Earnings from Subsidiary Companies		-53,746
18	Other (provide details in footnote): Change in Current Assets	-46,569,903	-12,485,946
19	Change in Other, Net	-35,112,298	24,694,768
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	893,361,000	428,791,984
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-744,166,999	-509,191,781
27	Gross Additions to Nuclear Fuel	-12,206,500	-46,911,677
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-1,342,931	-677,975
30	(Less) Allowance for Other Funds Used During Construction	-16,834,794	-13,228,664
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-740,881,636	-543,552,769
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	3,413,076	43,055,634
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-410,000	-210,000
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)	-625,424,547	-404,961,139
45	Proceeds from Sales of Investment Securities (a)	625,424,547	404,961,139

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	12/31/2006	End of 2006/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	2,613,840	-4,834,334
54	Other	-706	
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-735,265,426	-505,541,469
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		744,279,609
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):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	34,068,081	744,279,609
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-48,299,998	-102,999,998
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Decrease in Intercompany Notes, Other		-165,752,932
78	Net Decrease in Short-Term Debt (c)	-102,000,000	-190,867,000
79	Other	-125,586	-1,297,477
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)	-352,519,754	281,850,343
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-194,424,180	205,100,858
87			
88	Cash and Cash Equivalents at Beginning of Period	216,074,179	10,973,321
89			
90	Cash and Cash Equivalents at End of period	21,649,999	216,074,179

Schedule Page: 120 Line No.: 26 Column:

Decrease of $21,703,482 from original 12/31/05 filing is due to reclassification to include Allowance for Borrowed Funds used during Construction (previously reported on line 30) of $8,474,818 and move Allowance for Other Funds used during Construction of $13,228,664 to line 26.

Schedule Page: 120 Line No.: 30 Column:

Decrease of $21,703,482 from original 12/31/05 filing is due to reclassification to include Allowance for Other Funds used during Construction of $13,228,664 and move Allowance for Borrowed Funds used during Contruction of $8,474,818 to line 26.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/Q4

NOTES TO FINANCIAL STATEMENTS

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

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

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

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 DISCLOSURE

Cash payments for interest and income taxes for 2006 were approximately $152 million and $296 million, respectively.

The expense associated with special assessments levied under the Atomic Energy Act of 1954 as amended by Title XI of the Energy Policy Act of 1993 and recorded in account 518 in 2006 was $2,004,539. The payment made in November 2006 for such special assessments totaled $2,126,072.

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). Prior to February 8, 2006, the Parent was subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA 1935), as amended.

Our reportable segments are: PEC, PEF and Coal and Synthetic Fuels. Our PEC and PEF segments are primarily engaged in the generation, transmission, distribution and sale of electricity. Our Coal and Synthetic Fuels segment is primarily engaged in the production and sale of coal-based solid synthetic fuels as defined under the Internal Revenue Code (the Code), the operation of synthetic fuels facilities for third parties, and coal terminal services. Our Corporate and Other segment (Corporate and Other) is comprised of the activities of the Parent and Progress Energy Service Company (PESC) as well as nonregulated businesses, which do not separately meet the disclosure requirements as a 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.

Diversified business revenues and expenses represent the operating activities of our consolidated nonregulated operations, primarily the Coal and Synthetic Fuels segment. These operations are separate and distinct businesses from the Utilities.

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 2005 and 2004 have been reclassified to conform to the 2006 presentation.

C. Consolidation of Variable Interest Entities

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities 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, 2006, the aggregate additional maximum loss exposure that we could be required to record in our income statement as a result of these arrangements was $7 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 Code. At December 31, 2006, 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 $45 million, $44 million and $42 million in 2006, 2005 and 2004, respectively. The generation capacity of the entity's power plant is approximately 835 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 20 limited liability partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. At December 31, 2006, the aggregate maximum loss exposure that PEC could be required to record on its income statement as a result of these arrangements totals $21 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 three variable interest entities for which PEF is not the primary beneficiary. These arrangements include investments in one venture capital fund, one building lease with a special-purpose entity and one operating lease with a special-purpose entity. At December 31, 2006, the aggregate maximum loss exposure that PEF could be required to record in its income statement as a result of these arrangements was $57 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. Diversified business revenues are generally recognized at the time products are shipped or as services are rendered. Leasing activities are accounted for in accordance with SFAS No. 13, "Accounting for Leases." Revenues related to design and construction of wireless infrastructure are recognized upon completion of services for each completed phase of design and construction. Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. 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 recoveries that are deferred through fuel clauses established by the Utilities' regulators. These clauses allow the Utilities to recover fuel 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 electric operating revenues and taxes other than on income in the statements of income for the years ended December 31 were as follows:

(in millions)	**2006**	2005	2004
Progress Energy	**$ 293**	$ 258	$ 240
PEC	**94**	91	89
PEF	**199**	167	151

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 agreements approved by the SEC pursuant to Section 13(b) of PUHCA 1935. 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. The repeal of PUHCA 1935 and subsequent regulation by the FERC did not change our current intercompany services.

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 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 asset retirement obligations (ARO), 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

For financial reporting purposes, 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 5).

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 freezes North Carolina electric utility base rates for a five-year period ending in December 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn 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. During the rate freeze period, the legislation provides for the amortization and recovery of 70 percent of the original estimated compliance costs while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per 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. Inventories are valued at the lower of average 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.

DIVERSIFIED BUSINESS PROPERTY

Diversified business property is stated at cost less accumulated depreciation. If an impairment is recognized on an asset, the fair value becomes its new cost basis. The costs of renewals and betterments are capitalized. The costs of repairs and maintenance are charged to expense as incurred. For properties other than oil and gas properties, depreciation is computed on a straight-line basis using the estimated useful lives disclosed in Note 5B. Depletion of mineral rights is provided on the units-of-production method based upon the estimates of recoverable amounts of clean mineral.

We use the full-cost method to account for our oil and gas properties. Under the full-cost method, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of oil and gas reserves are capitalized. These capitalized costs include the costs of all unproved properties and internal costs directly related to acquisition and exploration activities. The amortization base also includes the estimated future cost to develop proved reserves. Except for costs of unproved properties and major development projects in progress, all costs are amortized using the units-of-production method on a country-by-country basis over the life of our proved reserves. Accordingly, all property acquisition, exploration, and development costs of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals, are capitalized as incurred, including internal costs directly attributable to such activities. Related interest expense incurred during property development activities is capitalized as a cost of such activity. Net capitalized costs of unproved property are reclassified as proved property and well costs when related proved reserves are found. Costs to operate and maintain wells and field equipment are expensed as incurred. In accordance with Rule 4-10 of Regulation S-X, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless certain significance tests are met. During 2006, we sold our natural gas drilling and production business, and we met the significance tests necessary to recognize a gain on the transaction (See Note 3B).

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 being 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 have been allocated to profitable subsidiaries in accordance with a PUHCA 1935 order. 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) in the Consolidated Statements of Income. Interest expense on tax deficiencies 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, including uncertain tax benefits, 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. Tax reserves are recorded for uncertain tax benefits when it is probable that the tax position will be disallowed and the amount of the disallowance 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. 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 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 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.

Under the full-cost method of accounting for oil and gas properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. The ceiling test takes into consideration the prices of qualifying cash flow hedges as of the balance sheet date. If the ceiling (discounted revenues) is not equal to or greater than total capitalized costs, we are required to write-down capitalized costs to this level. We performed this ceiling test calculation every quarter prior to the sale of our natural gas drilling and production business (See Note 3B). No write-downs were required in 2006, 2005 or 2004.

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

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)"

In September 2006, the FASB issued 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). SFAS No. 158 requires an entity to recognize in its statement of financial condition the funded status of its 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 employer's fiscal year (with limited exceptions). SFAS No. 158 also requires an entity to recognize changes in the funded status of a pension or other postretirement benefit plan within accumulated other comprehensive income (AOCI), net of tax, to the extent such changes are not recognized in earnings as components of net periodic cost. SFAS No. 158 does not permit retrospective application of its provisions. The recognition and disclosure provisions of SFAS No. 158 were implemented by us as of December 31, 2006. The implementation of SFAS No. 158 had no impact on reported net income.

The following is a summary of the incremental effect of applying the provisions of SFAS No. 158 on individual line items of the Balance Sheets of the Progress Registrants at December 31, 2006.

Progress Energy

(in millions)	Before	Adjustments	After Application of SFAS No. 158
Regulatory assets	$ 892	$ 339	$ 1,231
Intangibles, net	39	(39)	-
Total assets	25,401	300	25,701
Liabilities of discontinued operations	185	4	189
Income taxes accrued	287	(3)	284
Other current liabilities	746	9	755
Noncurrent income tax liabilities	255	51	306
Accrued pension and other benefits	791	166	957
Accumulated other comprehensive loss	(122)	73	(49)
Total capitalization and liabilities	25,401	300	25,701

PEC

(in millions)	Before		After Application of SFAS No. 158
Regulatory assets	$ 534	$ 243	$ 777
Other assets and deferred debits	180	(25)	155
Total assets	11,802	218	12,020
Income taxes accrued	69	(1)	68
Other current liabilities	152	2	154
Noncurrent income tax liabilities	855	54	909
Accrued pension and other benefits	501	80	581
Accumulated other comprehensive loss	(84)	83	(1)
Total capitalization and liabilities	11,802	$ 218	12,020

PEF

(in millions)	Before		After Application of SFAS No. 158
Regulatory assets	$ 330	$ 124	$ 454
Prepaid pension cost	221	(47)	174
Total assets	8,516	77	8,593
Other current liabilities	87	2	89
Noncurrent income tax liabilities	465	1	466
Accrued pension and other benefits	258	74	332
Total capitalization and liabilities	8,516	$ 77	8,593

Amounts for PEC and PEF that would otherwise be recorded in AOCI pursuant to SFAS No. 158 are recorded as regulatory assets consistent with the recovery of the related costs through the ratemaking process.

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

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). Enterprises must adopt FIN 48 through a cumulative effect adjustment to retained earnings at the beginning of their first fiscal year that begins after December 15, 2006, which for us was January 1, 2007. FIN 48 applies to all tax positions within the scope of SFAS No. 109, "Accounting for Income Taxes," and includes tax positions taken and tax positions expected to be taken. 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. FIN 48 also provides guidance on the related derecognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. We are still in the process of assessing the impact of FIN 48 on our various income tax positions. The cumulative effect adjustment to retained earnings upon adoption of FIN 48 could have a material impact on our financial statements.

SFAS No. 157, "Fair Value Measurements"

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). SFAS No. 157 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 fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. We will implement SFAS No. 157 as of January 1, 2008, applying the provisions retrospectively for derivative accounting and prospectively for all other valuations. We are currently evaluating the impact adoption may have on our financial condition, results of operations and cash flows.

Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). In practice, some companies currently use the "rollover" method, which focuses on the impact of a misstatement on the income statement. Other companies use the "iron curtain" method, which focuses on the impact of a misstatement on the balance sheet. SAB 108 requires companies to use a "dual approach" in quantifying financial statement misstatements. If an error is determined to be material under either approach, the financial statements must be adjusted. SAB 108 also provides transition guidance for correcting errors existing in prior years.

The SEC permits two methods for the initial application of SAB 108. A company can elect to restate prior financial statements as if the "dual approach" had always been used, or it can record a cumulative effect, with any correcting adjustments recorded to the carrying values of assets and liabilities as of the beginning of the implementation year with the offsetting adjustment recorded to the opening balance of retained earnings. Companies using the "cumulative effect" transition method must disclose the nature and amount of each individual error, including when and how each error being corrected arose. They must also disclose the fact that the errors had previously been considered immaterial. Companies do not have to restate prior period financial statements at initial application so long as management properly applied its previous approach.

SAB 108 is effective for us at December 31, 2006. The implementation of SAB 108 did not have a material effect on our financial position or results of operations, and we did not record an adjustment to beginning retained earnings as permitted by SAB 108.

3. DIVESTITURES

A. CCO - Georgia Operations

On December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of Progress Ventures, Inc.'s (PVI) Competitive Commercial Operations (CCO) physical and commercial assets, which include approximately 1,900 MW of power generation facilities in Georgia, as well as forward gas and power contracts, gas transportation, storage and structured power and other contracts, including the full requirements contracts with 16 Georgia Electric Membership Cooperatives (the Georgia Contracts). The operations of CCO were previously included in the former Progress Ventures segment. We expect to complete the disposition plan in 2007. As a result of the disposition plan, we recorded an after-tax estimated loss of $226 million in December 2006. In 2007, we anticipate recording additional material charges in discontinued operations related to the disposition plan. These additional charges relate primarily to costs to be incurred to exit the Georgia Contracts under SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." These costs could exceed $200 million after-tax.

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. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $36 million, $39 million and $40 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $14 million, $14 million and $15 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)		2006		2005		2004
Revenues	$	**754**	$	627	$	168
Loss before income taxes	$	**(92)**	$	(93)	$	(39)
Income tax benefit		**35**		39		16
Net loss from discontinued operations		**(57)**		(54)		(23)
Estimated loss on disposal of discontinued operations, including income tax benefit of $123		**(226)**		-		-
Loss from discontinued operations	$	**(283)**	$	(54)	$	(23)

B. Natural Gas Drilling and Production

On October 2, 2006, we sold our natural gas drilling and production business (Gas) to EXCO Resources, Inc. 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 Corporation (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.

In December 2004, we sold certain gas-producing properties and related assets owned by Winchester Production, which were previously included in the former Progress Ventures segment. Net proceeds of approximately $251 million were used to reduce debt. Because the sale significantly altered the ongoing relationship between capitalized costs and remaining proved reserves, under the full-cost method of accounting, the pre-tax gain of $56 million was recognized in earnings rather than as a reduction of the basis of our remaining oil and gas properties. Upon the sale of Gas, the gain was reclassed from continuing operations to earnings from discontinued operations.

The accompanying consolidated financial statements have been restated for all periods presented to reflect all 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. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $13 million, $13 million and $14 million, respectively. 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, 2005 and 2004 was $16 million, $26 million and $27 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)		2006		2005		2004
Revenues	$	**192**	$	159	$	162
Earnings before income taxes	$	**135**	$	73	$	127
Income tax expense		**(53)**		(25)		(51)
Net earnings from discontinued operations		**82**		48		76
Gain on disposal of discontinued operations, including income tax expense of $188		**300**		-		-
Earnings from discontinued operations	$	**382**	$	48	$	76

C. 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 owns a 320 MW dual-fuel combustion turbine electric generation facility in DeSoto County, Fla., and Rowan owns 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 have been restated for all periods presented to 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. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $6 million, $13 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, 2005 and 2004 was $3 million, $8 million and $8 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)		**2006**		2005		2004
Revenues	**$**	**64**	$	67	$	72
Earnings before income taxes	**$**	**15**	$	5	$	13
Income tax expense		**(5)**		(2)		(5)
Net earnings from discontinued operations		**10**		3		8
Loss on disposal of discontinued operations, including income tax benefit of $37		**(67)**		-		-
(Loss) earnings from discontinued operations	**$**	**(57)**	$	3	$	8

D. 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.

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 have been restated for all periods presented to 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. Interest expense allocated was $1 million for each of the years ended December 31, 2005 and 2004. 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, 2005 and 2004 was $1 million, $8 million and $6 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)		**2006**		2005		2004
Revenues	**$**	**18**	$	76	$	69
Earnings (loss) before income taxes and minority interest	**$**	**7**	$	11	$	(9)
Income tax (expense) benefit		**(4)**		(3)		2
Minority interest		**(5)**		(4)		-
Net (loss) earnings from discontinued operations		**(2)**		4		(7)
Gain on disposal of discontinued operations, including income tax expense of $8 and minority interest of $35		**28**		-		-
Earnings (loss) from discontinued operations	**$**	**26**	$	4	$	(7)

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.

E. Dixie Fuels and Other Fuels Business

On March 1, 2006, we sold our 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 operating under long-term contracts with PEF. 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. The other fuels business is Progress Materials, Inc. and is expected to be sold in 2007.

The accompanying consolidated financial statements have been restated for all periods presented to 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. Interest expense allocated was $1 million for each of the years ended December 31, 2006, 2005 and 2004. We ceased recording depreciation upon classification of the assets as discontinued operations. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $1 million, $2 million and $3 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)		**2006**		2005		2004
Revenues	**$**	**20**	$	32	$	25
Earnings before income taxes	**$**	**11**	$	8	$	3
Income tax expense		**(4)**		(3)		(1)
Net earnings from discontinued operations		**7**		5		2
Gain on disposal of discontinued operations, including income tax expense of $1		**2**		-		-
Earnings from discontinued operations	**$**	**9**	$	5	$	2

F. Coal Mining Businesses

On November 14, 2005, our board of directors approved a plan to divest of five subsidiaries of Progress Fuels engaged in the coal mining business. 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. The remaining coal mining operations are expected to be sold in 2007.

The accompanying consolidated financial statements have been restated for all periods presented to 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. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $1 million, $3 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 years ended December 31, 2005 and 2004 was $10 million and $9 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)		**2006**		2005		2004
Revenues	$	**84**	$	184	$	160
Loss before income taxes	$	**(11)**	$	(16)	$	(17)
Income tax benefit		**7**		5		12
Net loss from discontinued operations		**(4)**		(11)		(5)
Loss on disposal of discontinued operations, including income tax benefit of $16		**(10)**		-		-
Loss from discontinued operations	$	**(14)**	$	(11)	$	(5)

G. 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 have been restated for all periods presented to 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. Interest expense allocated for the years ended December 31, 2005 and 2004 was $4 million and $16 million, respectively. We ceased recording depreciation upon classification of Progress Rail as discontinued operations in February 2005. After-tax depreciation expense during the years ended December 31, 2005 and 2004 was $3 million and $10 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	**2006**	2005	2004
Revenues	**$ -**	$ 358	$ 1,127
Earnings before income taxes	**$ -**	$ 8	$ 50
Income tax expense	**-**	(3)	(21)
Net earnings from discontinued operations	**-**	5	29
Loss on disposal of discontinued operations, including income tax (expense) benefit of $(6) and $15, respectively	**(6)**	(25)	-
(Loss) earnings from discontinued operations	**$ (6)**	$ (20)	$ 29

In February 2004, we sold the majority of the assets of Railcar Ltd., a subsidiary of Progress Rail, to The Andersons, Inc. for proceeds of approximately $82 million before transaction costs and taxes of approximately $13 million. In 2002, we had recognized pre-tax impairment of $59 million to write-down the assets to our estimated fair value less costs to sell. In July 2004, we sold the remaining assets, which had been classified as held for sale, to a third party for net proceeds of $6 million.

H. Net Assets of Discontinued Operations

Included in net assets of discontinued operations are the assets and liabilities of CCO, the remaining coal mining operations and other fuels business at December 31, 2006, and the assets and liabilities of CCO, Gas, DeSoto and Rowan, PT LLC, Dixie Fuels, the five coal mining businesses and other fuels business at December 31, 2005. The major balance sheet classes included in assets and liabilities of discontinued operations in the Consolidated Balance Sheets were as follows:

(in millions)	**December 31,**	December 31, 2005
Accounts receivable	**$ 45**	$ 115
Inventory	**24**	50
Other current assets	**28**	47
Total property, plant and equipment, net	**573**	1,899
Total other assets	**217**	455
Assets of discontinued operations	**$ 887**	$ 2,566
Accounts payable	**$ 43**	$ 87
Accrued expenses	**122**	233
Long-term liabilities	**24**	222
Liabilities of discontinued operations	**$ 189**	$ 542

I. 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.

J. 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 will be received over time, which is typical of such sales in the industry. Gains from the sales will be 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, $30 million and $8 million in the years ended December 31, 2006, 2005 and 2004, respectively. In the event that the synthetic fuels tax credits from the Colona facility are reduced, including an increase in the price of oil that could limit or eliminate synthetic fuels tax credits, the amount of proceeds realized from the sale could be significantly impacted.

K. North Carolina Natural Gas Corporation

On September 30, 2003, we sold North Carolina Natural Gas Corporation (NCNG) and our equity investment in Eastern North Carolina Natural Gas Company to Piedmont Natural Gas Company, Inc. During 2004, we recorded an additional tax gain of approximately $6 million due to final tax adjustments related to the divestiture of NCNG.

4. ACQUISITIONS

In May 2005, Winchester Production, an indirectly wholly owned subsidiary of Progress Fuels, acquired a 50 percent interest in approximately 11 natural gas producing wells and proven reserves of approximately 25 billion cubic feet equivalent (Bcf) 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 or 2004. 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 3B).

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:

	Depreciable	Progress Energy		PEC		PEF	
(in millions)	Lives	**2006**	2005	**2006**	2005	**2006**	2005
Production plant	7-43	**$ 12,685**	$ 12,489	**$ 8,422**	$ 8,260	**$ 4,078**	$ 4,039
Transmission plant	17-75	**2,509**	2,353	**1,300**	1,264	**1,209**	1,089
Distribution plant	13-55	**7,351**	7,015	**3,992**	3,838	**3,359**	3,177
General plant and other	5-35	**1,198**	1,083	**642**	632	**556**	451
Utility plant in service		**$ 23,743**	$ 22,940	**$ 14,356**	$ 13,994	**$ 9,202**	$ 8,756

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. 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 8.7%, 5.6% and 7.2% in 2006, 2005 and 2004, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8% in 2006 and 7.8% in 2005 and 2004.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.7%, 2.5% and 2.2% in 2006, 2005 and 2004, respectively. The depreciation provisions related to utility plant were $628 million, $556 million and $463 million in 2006, 2005 and 2004, 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 21B).

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, 2006, 2005 and 2004 was $140 million, $136 million and $137 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 2.8%, 2.7% and 2.1% in 2006, 2005 and 2004, respectively. The depreciation provisions related to utility plant were $389 million, $365 million and $275 million in 2006, 2005 and 2004, 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 7A) and Clean Smokestacks Act amortization (See Note 21B).

During 2004, PEC met the requirements of both the NCUC and the SCPSC for the implementation of two depreciation studies that allowed the utility to reduce the rates used to calculate depreciation expense. The reduction was primarily due to extended lives at each of PEC's nuclear units. The reduced depreciation rates were effective January 1, 2004.

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.7% in 2006 and 2.3% in 2005 and 2004. The depreciation provisions related to utility plant were $239 million, $191 million and $188 million in 2006, 2005 and 2004, 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, 2006, 2005 and 2004 was $109 million, $107 million and $105 million, respectively, for PEC and $31 million, $29 million and $32 million, respectively, for PEF. These costs were included in fuel used for electric generation in the Statements of Income.

B. Diversified Business Property

Progress Energy

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

(in millions)	**2006**	2005
Equipment (3-25 years)	**$ 66**	$ 79
Land and mineral rights	**16**	17
Buildings and plants (5-40 years)	**54**	66
Rail equipment (3-20 years)	**-**	37
Computers, office equipment and software (3-10 years)	**2**	2
Construction work in progress	**1**	2
Accumulated depreciation	**(108)**	(125)
Diversified business property, net	**$ 31**	$ 78

Diversified business depreciation expense was $13 million for December 31, 2006, and $22 million for December 31, 2005 and 2004.

PEC

Net diversified business property was $7 million at both December 31, 2006 and 2005. 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, 2006 and 2005. Diversified business depreciation expense was less than $1 million each in 2006, 2005 and 2004. Net diversified business property is included in miscellaneous other property and investments on the Consolidated Balance Sheets.

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). 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:

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**	**-**

2005 (in millions) Subsidiary	Facility	Company Ownership Interest	Plant	Accumulated	Construction Work in Progress
PEC	Mayo	83.83% $	518 $	255 $	1
PEC	Harris	83.83%	3,146	1,459	17
PEC	Brunswick	81.67%	1,623	921	23
PEC	Roxboro Unit 4	87.06%	355	153	10
PEF	Crystal River Unit 3	91.78%	808	493	48
PEF	Intercession City Unit P11	66.67%	24	4	-

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, 2006 and 2005, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant, net of accumulated depreciation for PEC, totaled $30 million and $31 million, respectively. No costs related to nuclear decommissioning of irradiated plant were recorded at December 31, 2006 and 2005 at PEF. At December 31, 2006 and 2005, additional PEF-related asset retirement costs, net of accumulated depreciation, of $126 million and $137 million, respectively, were recorded at Progress Energy. The fair value of funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $735 million and $640 million at December 31, 2006 and 2005, respectively, for PEC and $552 million and $493 million, respectively, for PEF. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 7A).

PEC's decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2006, 2005 and 2004. Management believes that 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 asset retirement obligations, which are included in depreciation and amortization expense, were $96 million, $90 million and $83 million in 2006, 2005 and 2004, respectively, for PEC and $27 million, $78 million and $77 million in 2006, 2005 and 2004, 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)	**2006**	2005	**2006**	2005	**2006**	2005
Removal costs	**$ 1,341**	$ 1,316	**$ 727**	$ 661	**$ 614**	$ 655
Nonirradiated decommissioning costs	**137**	132	**76**	71	**61**	61
Dismantlement costs	**124**	123	**-**	-	**124**	123
Non-ARO cost of removal	**$ 1,602**	$ 1,571	**$ 803**	$ 732	**$ 799**	$ 839

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. Extended 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. An application to extend the licenses 20 years for the Brunswick units was approved in June 2006. 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. An application to extend this license 20 years is expected to be submitted 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 $145 million at December 31, 2006 and 2005, 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 the synthetic fuels operations. The related asset retirement costs, net of accumulated depreciation, totaled $3 million at December 31, 2006 and 2005.

The following table presents the changes to the AROs during the years ended December 31, 2006 and 2005. Additions relate primarily to asbestos abatement at the Utilities. 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, 2005	$ 1,261	$ 2	$ 924	$ 337
Additions	50	-	23	27
Accretion expense	65	1	51	14
Revisions to prior estimates	(137)	-	(49)	(88)
Asset retirement obligations at December 31, 2005	1,239	3	949	290
Accretion expense	**72**	**-**	**57**	**15**
Revisions to prior estimates	**(8)**	**-**	**(2)**	**(6)**
Asset retirement obligations at December 31, 2006	**$ 1,303**	**$ 3**	**$ 1,004**	**$ 299**

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 $33 million with respect to the primary coverage, $36 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 an insured nuclear incident exceed $300 million (currently available through commercial insurers), each company would be subject to pro rata assessments of up to $100 million for each reactor owned per occurrence. 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.

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, 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. For nuclear liability claims arising out of terrorist acts, the primary level available through commercial insurers is now subject to an industry aggregate limit of $300 million. The second level of coverage obtained through the assessments discussed above would continue to apply to losses exceeding $300 million and would provide coverage in excess of any diminished primary limits due to terrorist acts.

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)	**2006**	2005	**2006**	2005	**2006**	2005
Trade accounts receivable	**$ 628**	$ 661	**$ 285**	$ 336	**$ 288**	$ 263
Unbilled accounts receivable	**227**	227	**157**	158	**55**	60
Notes receivable	**57**	83	**-**	-	**-**	-
Other receivables	**46**	45	**36**	28	**5**	14
Allowance for doubtful accounts receivable	**(28)**	(19)	**(5)**	(4)	**(8)**	(6)
Total receivables	**$ 930**	$ 997	**$ 473**	$ 518	**$ 340**	$ 331

B. Inventory

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Fuel for production	**$ 470**	$ 321	**$ 230**	$ 185	**$ 240**	$ 136
Inventory for sale	**34**	61	**-**	-	**-**	-
Materials and supplies	**443**	406	**247**	240	**194**	166
Emission allowances	**22**	35	**20**	26	**2**	9
Total current inventory	**$ 969**	$ 823	**$ 497**	$ 451	**$ 436**	$ 311

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits for Progress Energy and PEC of $44 million at December 31, 2006 and 2005.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits for Progress Energy, PEC and PEF of $14 million, $13 million and $1 million, respectively, at December 31, 2005. 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)		2006		2005
Deferred fuel cost - current (Note 7B)	$	**196**	$	602
Deferred fuel cost - long-term (Note 7B)		**114**		31
Deferred impact of ARO - PEC (Note 1D)		**282**		281
Income taxes recoverable through future rates (Note 14)		**114**		81
Loss on reacquired debt (Note 1D)		**46**		50
Storm deferral (Notes 7B and 7C)		**102**		227
Postretirement benefits (Note 16)		**373**		88
Derivative mark-to-market adjustment (Note 17)		**78**		6
Environmental (Notes 7B, 7C and 21A)		**72**		26
Other		**50**		64
Total long-term regulatory assets		**1,231**		854
Deferred fuel cost - current (Note 7C)		**(63)**		-
Deferred energy conservation cost and other current regulatory liabilities		**(13)**		(10)
Total current regulatory liabilities		**(76)**		(10)
Non-ARO cost of removal (Note 5D)		**(1,602)**		(1,571)
Deferred impact of ARO - PEF (Note 1D)		**(221)**		(225)
Net nuclear decommissioning trust unrealized gains (Note 5D)		**(330)**		(251)
Clean Smokestacks Act compliance (Note 21B)		**(333)**		(317)
Derivative mark-to-market adjustment (Note 17A)		**-**		(122)
Other		**(57)**		(41)
Total long-term regulatory liabilities		**(2,543)**		(2,527)
Net regulatory liabilities	$	**(1,192)**	$	(1,081)

PEC

(in millions)		2006		2005
Deferred fuel cost - current (Note 7B)	$	**196**	$	261
Deferred fuel cost - long-term (Note 7B)		**114**		31
Deferred impact of ARO (Note 1D)		**282**		281
Income taxes recoverable through future rates (Note 14)		**50**		22
Loss on reacquired debt (Note 1D)		**19**		21
Storm deferral (Note 7B)		**12**		19
Postretirement benefits (Note 16)		**243**		-
Environmental (Note 7B)		**15**		-
Other		**42**		47
Total long-term regulatory assets		777		421
Non-ARO cost of removal (Note 5D)		**(803)**		(732)
Net nuclear decommissioning trust unrealized gains (Note 5D)		**(171)**		(135)
Clean Smokestacks Act compliance (Note 21B)		**(333)**		(317)
Other		**(13)**		(12)
Total long-term regulatory liabilities		**(1,320)**		(1,196)
Net regulatory liabilities	$	**(347)**	$	(514)

PEF

(in millions)		2006		2005
Deferred fuel cost - current (Note 7C)	$	-	$	341
Storm deferral (Note 7C)		**90**		208
Income taxes recoverable through future rates (Note 14)		**64**		59
Loss on reacquired debt (Note 1D)		**27**		29
Postretirement benefits (Note 16)		**130**		7
Derivative mark-to-market adjustment (Note 17A)		**78**		6
Environmental (Notes 7C and 21A)		**57**		26
Other		**8**		16
Total long-term regulatory assets		**454**		351
Deferred fuel cost - current (Note 7C)		**(63)**		-
Deferred energy conservation cost and other current regulatory liabilities		**(13)**		(10)
Total current regulatory liabilities		**(76)**		(10)
Non-ARO cost of removal (Note 5D)		**(799)**		(839)
Deferred impact of ARO (Note 1D)		**(88)**		(80)
Net nuclear decommissioning trust unrealized gains (Note 5D)		**(159)**		(116)
Derivative mark-to-market adjustment (Note 17A)		**-**		(122)
Other		**(45)**		(32)
Total long-term regulatory liabilities		**(1,091)**		(1,189)
Net regulatory liabilities	$	**(713)**	$	(507)

Except for portions of deferred fuel costs and loss on reacquired debt, all regulatory assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. We expect to fully recover these assets and refund these 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. As further discussed in Note 21B, the Clean Smokestacks Act was enacted in 2002. The Clean Smokestacks Act freezes North Carolina electric utility base rates for a five-year period ending in December 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn 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. During the rate freeze period, the legislation provides for the amortization and recovery of 70 percent of the original estimated compliance costs while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. Subsequent to 2007, PEC's current North Carolina base rates will continue subject to traditional cost-based rate regulation.

FUEL COST RECOVERY

On May 3, 2006, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers for under-recovered fuel costs and to meet future expected fuel costs. On June 16, 2006, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceeding. The settlement agreement provided for a $23 million, or 4.6 percent, increase in rates. The increase was $4 million less than PEC originally requested due to adjustment of future fuel cost estimates agreed upon during settlement. Effective July 1, 2006, residential electric bills increased by $3.01 per 1,000 kWhs for fuel cost recovery. At December 31, 2006, PEC's South Carolina deferred fuel balance was $29 million, of which $5 million is expected to be collected after 2007 in accordance with the settlement agreement and, therefore, has been classified as a long-term regulatory asset.

On June 2, 2006, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. On September 25, 2006, the NCUC approved a settlement agreement filed jointly by PEC, the NCUC Public Staff and the Carolinas Industrial Group for Fair Utility Rates II. The settlement agreement provided for a $177 million, or 6.7 percent increase in rates effective October 1, 2006. The settlement agreement further provides for rate increases of $50 million in 2007 and $30 million in 2008 and for PEC to collect its existing deferred fuel balance by September 30, 2009. PEC initially sought an increase of $292 million, or 11.0 percent, but agreed to a three-year phase-in of the increase in order to address concerns regarding the magnitude of the proposed increase. PEC will be allowed to calculate and collect interest at 6% on the difference between its fuel factor proposed in its original request to the NCUC and the settlement agreement's factor. Effective October 1, 2006, residential electric bills increased by $4.87 per 1,000 kWhs for fuel cost recovery. At December 31, 2006, PEC's North Carolina deferred fuel balance was $281 million, of which $109 million is expected to be collected after 2007 in accordance with the settlement agreement and, therefore, has been classified as a long-term regulatory asset.

The Carolina Utility Customers Association (CUCA) appealed the NCUC's order on November 21, 2006 on the grounds that the NCUC does not have the statutory authority to establish fuel rates for more than one year. We anticipate filing a motion to dismiss during the first quarter of 2007. We cannot predict the outcome of this matter.

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. During each of 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. During each of 2006, 2005 and 2004, 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 $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 the fourth quarter of 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.

As discussed in Note 21B, PEC reclassified $29 million of expense from other, net to depreciation and amortization expense on the Consolidated Statements of Income for Clean Smokestacks Act amortization recognized during 2006.

The NCUC and SCPSC have 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. Accelerated cost recovery of these assets resulted in no additional expense in 2006, 2005 or 2004. Through December 31, 2006, PEC recorded total accelerated depreciation of $403 million.

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. Additionally, PEF will continue to recover and collect a return on Hines Unit 2 through the fuel clause through late 2007, when it will be transferred into base rates. This transfer will correspond with the in-service dates of Hines Unit 4, which will also be recovered through a base rate increase. 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 2006 threshold of $1.499 billion and thus no revenues were subject to revenue sharing. Both the 2006 base threshold of $1.499 billion and the 2006 cap of $1.549 billion will be adjusted annually for rolling average 10-year retail kWh sales growth. 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 return on equity (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 1 and September 15, 2006, PEF filed requests with the FPSC seeking increases to cover rising fuel, environmental compliance and energy conservation costs. PEF asked the FPSC to approve a $171 million, or 3.7 percent, increase in rates. Subsequently, on October 25 and October 31, 2006, PEF supplemented its September filings to reflect lower projected fuel costs for PEF. PEF's revised forecasts resulted in a $40 million, or 0.7 percent, increase in rates over 2006. On November 8, 2006, the FPSC approved PEF's supplemental filing. The new charges were effective January 1, 2007, and increased residential bills $0.78 for the first 1,000 kWhs. At December 31, 2006, PEF was over-recovered in fuel and capacity costs by $63 million and under-recovered in environmental compliance by $14 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 sulfur dioxide (SO_2) allowance costs associated with PEF's purported failure to utilize the most economical sources of coal at Crystal River Unit 4 and Crystal River

Unit 5 (CR4 and CR5) during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. The OPC claims that although 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 August 30, 2006, PEF filed a motion with the FPSC to dismiss the petition on the grounds that the OPC petition would require the FPSC to engage in retroactive ratemaking for rates previously approved under the fuel recovery clause. On September 13, 2006, the OPC filed a memorandum in opposition to PEF's motion to dismiss the petition. PEF's motion to dismiss was denied by the FPSC on December 19, 2006. A hearing on the matter has been scheduled by the FPSC for April 2, 2007. PEF believes that its coal procurement practices were prudent and that it has sound legal and factual arguments to successfully defend its position. 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 costs through PEF's fuel recovery clause. The uprate will increase CR3's gross output by approximately 180 MW. The uprate will take place in two stages: approximately 40 MW will be added through equipment modifications during the 2009 refueling outage and approximately 140 MW will be added by modifying the design of the plant during the 2011 refueling outage to use more highly enriched fuel. The design modifications will require a license amendment approved by the NRC. The project is estimated to cost approximately $382 million, which includes potential transmission system improvements and modifications to comply with environmental regulations. The costs 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 of uprate costs through PEF's fuel recovery clause was transferred to a separate docket filed on January 16, 2007. The FPSC has scheduled a hearing to be held May 23, 2007, to determine whether the uprate costs should be recovered through the fuel adjustment clause. If PEF does not receive approval to recover the uprate costs through the fuel adjustment clause, these costs will be recoverable through base rates, similar to other utility plant additions. 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. 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 kWhs 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 2006 and 2005, PEF recorded amortization of $122 million and $50 million, respectively, associated with the recovery of these storm costs.

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 current two-year storm surcharge, which equals approximately $3.61 on the average residential monthly customer bill of 1,000 kWhs, for an additional 12-month period to replenish its storm reserve. The requested extension, which would begin August 2007, would replenish the existing storm reserve by an estimated additional $130 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.

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 November 3, 2004, the FPSC approved PEF's petition for Determination of Need for the construction of a fourth unit at PEF's Hines Energy Complex. Hines Unit 4 is needed to maintain electric system reliability and integrity and to continue to provide adequate electricity to its ratepayers at a reasonable cost. The unit is planned for commercial operation in December 2007. Hines Unit 4 will be a combined cycle unit with a generating capacity of 461 MW (summer rating). The estimated total in-service cost of Hines Unit 4 approved as part of the Determination of Need was $286 million. If the actual cost is less than the original estimate, ratepayers will receive the benefit of such cost under-runs. Any costs that exceed this estimate will not be recoverable absent, among other things, extraordinary circumstances as found by the FPSC in subsequent proceedings. The current estimate of in-service cost exceeds the initial project estimate by approximately 12 percent to 15 percent due to what we believe to be extraordinary circumstances. Therefore, we believe that disallowance of these costs by the FPSC in subsequent proceedings is not probable. We cannot predict the outcome of this matter.

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. 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. PEC's investment in GridSouth totaled $33 million at December 31, 2006 and 2005. PEC expects to recover its investment.

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 startup costs in GridFlorida from retail ratepayers through base rates.

E. Nuclear License Renewals

On June 26, 2006, Brunswick received 20-year extensions from the NRC on the operating licenses for its two nuclear reactors. The operating licenses have been extended to 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.

F. FERC Market Power Mitigation

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two interim screens for assessing potential generation market power of applicants for wholesale market-based rates, and described additional analyses and mitigation measures that could be presented if an applicant did not pass one of the interim screens. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way. PEF does not have market-based rate authority for wholesale sales in peninsular Florida. Given the difficulty PEC believed it would experience in passing one of the interim screens, on September 6, 2005, PEC filed revisions to its market-based rate tariffs restricting them to sales outside PEC's control area and peninsular Florida and a new cost-based tariff for sales within PEC's control area. The FERC has accepted these revised tariffs.

8. GOODWILL AND OTHER 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 2005 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, 2006 and 2005, 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 2006 or 2005.

Included in the assets of discontinued operations at December 31, 2005, is the goodwill related to CCO. For CCO, the goodwill impairment tests were performed at the reporting unit level of our Effingham, Monroe, Walton and Washington nonregulated generating plants (Georgia Region), which is one level below CCO. As a result of our evaluation of certain business opportunities that impacted the future cash flows of our Georgia Region operations, we performed an interim 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 was previously reported within impairment of assets on the Consolidated Statements of Income. This impairment was reclassed to discontinued operations on the Consolidated Statements of Income during the fourth quarter of 2006 (See Note 3A).

The gross carrying amount and accumulated amortization of the intangible assets at December 31 were as follows:

	2006		2005	
(in millions)	**Gross Carrying Amount**	**Accumulated**	Gross Carrying	Accumulated
Synthetic fuels intangibles	**$ 107**	**$ (107)**	$ 134	$ (98)
Other	**6**	**(6)**	29	(6)
Total	**$ 113**	**$ (113)**	$ 163	$ (104)

All of our intangibles, except minimum pension liability adjustments, are subject to amortization. Synthetic fuels intangibles represent intangibles for synthetic fuels technology. Other intangibles are primarily acquired customer contracts, permits that are amortized over their respective lives and minimum pension liability adjustments.

PEC had intangible assets related to minimum pension liability adjustments of $17 million at December 31, 2005. PEF had intangible assets related to minimum pension liability adjustments of $2 million at December 31, 2005. Due to the adoption of SFAS No. 158 in 2006, minimum pension liability adjustments and related intangible assets are no longer recorded (See Note 2).

Amortization expense recorded on intangible assets was $9 million for the year ended December 31, 2006, and $19 million for both years ended December 31, 2005 and 2004. No amortization expense on intangible assets was recorded at PEC and PEF for each of the years ended December 31, 2006, 2005 and 2004. No annual amortization expense for intangible assets is expected for 2007 through 2011.

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 "idle" 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 is reported within impairment of assets on the Consolidated Statements of Income. This charge represents the entirety of the synthetic fuels intangible assets; these assets had been reported within the Coal and Synthetic Fuels segment. Following a significant decrease in oil prices, our synthetic fuels facilities resumed limited production of synthetic fuels in September and October 2006, which continued through the end of 2006.

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 and 2005, we recorded pre-tax long-lived asset and investment impairments and other charges of $65 million and $1 million, respectively. PEC recorded pre-tax long-lived asset and investment impairments and other charges of $1 million in both 2006 and 2005. No impairments were recorded in 2004.

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 is reported within impairment of assets on the Consolidated Statements of Income. 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 the Coal and Synthetic Fuels segment. As discussed in Note 8, our synthetic fuels facilities resumed limited production of synthetic fuels in September and October 2006, which continued through the end of 2006.

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 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. 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. No impairments were recorded in 2004.

10. EQUITY

A. Common Stock

Progress Energy

At December 31, 2006 and 2005, we had 500 million shares of common stock authorized under our charter, of which 256 million shares and 252 million shares, respectively, were outstanding. During 2006, 2005 and 2004, respectively, we issued approximately 4.2 million, 4.8 million and 1.7 million shares of common stock, resulting in approximately $185 million, $208 million and $73 million in proceeds. Included in these amounts for 2006, 2005 and 2004, respectively, were approximately 1.6 million, 4.6 million and 1.4 million shares for proceeds of approximately $70 million, $199 million and $62 million, to meet the requirements of the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan.

At December 31, 2006 and 2005, we had approximately 54 million shares and 58 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, 2006, there were no significant restrictions on the use of retained earnings (See Note 12).

PEC

At December 31, 2006 and 2005, 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, 2006, 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, 2006 and 2005, 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, 2006, 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, 2006 and 2005, 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 2.3 million and 2.9 million ESOP suspense shares at December 31, 2006 and 2005, respectively, with a fair value of $112 million and $126 million, respectively. ESOP shares allocated to plan participants totaled 10.9 million and 11.4 million at December 31, 2006 and 2005, 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 $14 million, $18 million and $21 million for the years ended December 31, 2006, 2005 and 2004, respectively. Total matching and incentive costs were approximately $23 million, $30 million and $32 million for the years ended December 31, 2006, 2005 and 2004, 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.

PEC

PEC's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $8 million, $11 million and $12 million for the years ended December 31, 2006, 2005 and 2004, respectively. Total matching and incentive costs were approximately $13 million, $17 million and $18 million for the years ended December 31, 2006, 2005 and 2004, respectively.

PEF

PEF's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $2 million, $4 million and $5 million for the years ended December 31, 2006, 2005 and 2004, respectively. Total matching and incentive costs were approximately $4 million, $6 million and $7 million for the years ended December 31, 2006, 2005 and 2004, respectively.

STOCK OPTIONS

Pursuant to our 1997 Equity Incentive Plan and 2002 Equity Incentive Plan, 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. An immaterial number of stock options were granted in 2004 and no stock options have been granted in 2005 or 2006. 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, 2006, 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	7.0	$ 43.58
Granted	-	-
Forfeited	(0.1)	44.75
Canceled	(0.2)	43.74
Exercised	(2.7)	43.37
Options outstanding, December 31	4.0	43.70
Options exercisable, December 31	4.0	43.70

The options outstanding and exercisable at December 31, 2006, had a weighted-average remaining contractual life of 5.8 years and an aggregate intrinsic value of $22 million. Total intrinsic value of options exercised during the year ended December 31, 2006, was $10 million. Total intrinsic value of options exercised during the year ended December 31, 2005, was less than $1 million. The total intrinsic value of options exercised during the year ended December 31, 2004, was $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 with the following weighted-average assumptions:

	2004
Risk-free interest rate	4.22%
Dividend yield	5.19%
Volatility factor	20.30%
Weighted-average expected life of the options (in years)	10

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.

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		2004
Net income, as reported	$	697	$	759
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects		2		10
Pro forma net income	$	695	$	749
Earnings per share				
Basic - as reported	$	2.82	$	3.13
Basic - pro forma		2.81		3.09
Diluted - as reported		2.82		3.12
Diluted - pro forma		2.81		3.08

As of December 31, 2006, all options were fully vested and no compensation expense related to stock options is expected in future periods.

Cash received from the exercise of stock options totaled $115 million, $8 million and $18 million, respectively, during the years ended December 31, 2006, 2005 and 2004. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2006, was $4 million. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2005 and 2004 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 are fully vested and no compensation expense related to stock options is expected in future periods.

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		2004
Net income, as reported	$	493	$	461
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects		2		7
Pro forma net income	$	491	$	454

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 are fully vested and no compensation expense related to stock options is expected in future periods.

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		2004
Net income, as reported	$	260	$	335
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects		1		2
Pro forma net income	$	259	$	333

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. The two primary active stock-based compensation programs are the Performance Share Sub-Plan (PSSP) and the Restricted Stock Awards (RSA) program, both of which were established pursuant to our 1997 Equity Incentive Plan and were continued under our 2002 Equity Incentive Plan, as amended and restated from time to time.

We granted cash-settled PSSP awards prior to 2005. Beginning in 2005, we are granting stock-settled PSSP awards. Under the terms of the cash-settled 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, the performance shares. The PSSP has two equally weighted performance measures, both of which are based on our results as compared to a peer group of utilities. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. Compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. 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 certain subsequent adjustments related to our results as compared to the peer group of utilities. PSSP cash-settled liabilities totaling $4 million, $5 million and $7 million were paid in the years ended December 31, 2006, 2005 and 2004, respectively. A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2006, and changes during the year then ended is presented below:

	Number of Stock-Settled Performance Shares (a)		Weighted-Average
Beginning balance	540,588	$	44.24
Granted	556,431		44.27
Paid	(54)		44.27
Vested	-		-
Forfeited	(52,382)		44.25
Ending balance	1,044,583	$	44.26

(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.

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

The 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, 2006, and changes during the year then ended, is presented below:

	Number of Restricted Shares	Weighted-Average
Beginning balance	588,308	$ 43.27
Granted	168,800	44.51
Vested	(102,836)	41.87
Forfeited	(50,034)	43.68
Ending balance	604,238	$ 43.82

For the years ended December 31, 2005 and 2004, the weighted-average grant date fair value of restricted stock granted was $42.56 and $46.95, respectively.

The total fair value of restricted stock vested during the years ended December 31, 2006, 2005 and 2004 was $4 million, $7 million and $16 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million, $8 million and $7 million during the years ended December 31, 2006, 2005 and 2004, respectively.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $25 million for the year ended December 31, 2006, with a recognized tax benefit of $10 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $10 million, with a recognized tax benefit of $4 million, for each of the years ended December 31, 2005 and 2004. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2006, there was $33 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 2.1 years.

PEC

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $14 million for the year ended December 31, 2006, with a recognized tax benefit of $6 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $7 million, with a recognized tax benefit of $3 million, for each of the years ended December 31, 2005 and 2004. No compensation cost related to other stock-based compensation plans was capitalized.

PEF

Our Statements of Income included total recognized expense for other stock-based compensation plans of $7 million for the year ended December 31, 2006, with a recognized tax benefit of $3 million. The total expense recognized on our 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. The total expense recognized on our Statements of Income for other stock-based compensation plans was $2 million for the year ended December 31, 2004, 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 effect of the nonvested portion of restricted stock 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)	**2006**	2005	2004
Weighted-average common shares - basic	**250.4**	246.6	242.2
Net effect of dilutive stock-based compensation plans	**0.4**	0.4	0.9
Weighted-average shares - fully diluted	**250.8**	247.0	243.1

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 2.4 million, 3.0 million and 3.6 million for the years ended December 31, 2006, 2005 and 2004, respectively. There were 1.8 million, 2.9 million and 3.0 million stock options outstanding at December 31, 2006, 2005 and 2004, 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)	**2006**	2005	**2006**	2005	**2006**	2005
(Loss) gain on cash flow hedges	**$ (14)**	$ 55	**$ (5)**	$ (3)	**$ (1)**	$ -
Minimum pension liability adjustments	**-**	(160)	**-**	(119)	**-**	-
SFAS No. 158 benefits adjustment	**(39)**	-	**-**	-	**-**	-
Other	**4**	1	**4**	2	**-**	-
Total accumulated other comprehensive loss	**$ (49)**	$ (104)	**$ (1)**	$ (120)	**$ (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, 2006 and 2005, preferred stock outstanding consisted of the following:

(dollars in millions, except share and per share data)	Shares Authorized	Shares Outstanding	Redemption	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, 2006):

(in millions)			**2006**		2005
Progress Energy, Inc.					
Senior unsecured notes, maturing 2010-2031	6.98%	$	**2,600**	$	4,300
Unamortized fair value hedge gain, net			**(1)**		(3)
Unamortized premium and discount, net			**(18)**		(19)
Current portion of long-term debt			**-**		(404)
Long-term debt, net			**2,581**		3,874
PEC					
First mortgage bonds, maturing 2007-2033	5.76%		**2,200**		2,200
Pollution control obligations, maturing 2017-2024	3.74%		**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			**(21)**		(24)
Current portion of long-term debt			**(200)**		-
Long-term debt, net			**3,470**		3,667
PEF					
First mortgage bonds, maturing 2008-2033	5.39%		**1,630**		1,630
Pollution control obligations, maturing 2018-2027	3.66%		**241**		241
Senior unsecured notes, maturing 2008	5.77%		**450**		450
Medium-term notes, maturing 2007-2028	6.77%		**241**		289
Unamortized premium and discount, net			**(5)**		(8)
Current portion of long-term debt			**(89)**		(48)
Long-term debt, net			**2,468**		2,554
Florida Progress Funding Corporation (See Note 23)					
Debt to affiliated trust, maturing 2039	7.10%		**309**		309
Unamortized premium and discount, net			**(38)**		(39)
Long-term debt, net			**271**		270
Progress Capital Holdings, Inc.					
Medium-term notes, maturing 2007-2008	6.59%		**80**		140
Miscellaneous notes			**-**		2
Current portion of long-term debt			**(35)**		(61)
Long-term debt, net			**45**		81
Progress Energy consolidated long-term debt, net		**$**	**8,835**	$	10,446

At December 31, 2005, we classified $397 million, related to the retirement of $800 million in Progress Energy, Inc. 6.75% Senior Notes on March 1, 2006, as long-term debt. Settlement of this obligation was not expected to require the use of working capital in 2006 as we had the intent and ability to refinance this debt on a long-term basis.

On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010, receiving net proceeds of $397 million. These senior notes are unsecured. Interest on the Floating Rate Senior Notes is based on three-month London Inter Bank Offering Rate (LIBOR) plus 45 basis points and resets quarterly. We used the net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006. Pending the application of the proceeds described above, we invested the net proceeds in short-term, interest-bearing, investment-grade securities.

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, at a make-whole redemption price. The 6.05% Senior Notes were acquired at 100.274 percent of par, or approximately $351 million plus accrued interest, and the 5.85% Senior Notes were acquired at 101.610 percent of par, or approximately $406 million, plus accrued interest. The redemptions were funded with available cash on hand and no additional debt was incurred in connection with the redemptions. On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 53.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest. The redemption was funded with available cash on hand and no additional debt was incurred in connection with the redemption. See Note 20 for a discussion of losses on debt redemptions.

At December 31, 2006 and 2005, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2006 and 2005, 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, 2006:

(in millions)	Description	Total	Outstanding	Reserved(a)	Available
Progress Energy, Inc.	Five-year (expiring 5/3/11)	$ 1,130	$ -	$ (60)	$ 1,070
PEC	Five-year (expiring 6/28/10)	450	-	-	450
PEF	Five-year (expiring 3/28/10)	450	-	-	450
Total credit facilities		$ 2,030	$ -	$ (60)	$ 1,970

(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, 2006, Progress Energy, Inc. had a total amount of $60 million of letters of credit issued, which were supported by the RCA.

In addition to the committed RCAs at December 31, 2005, we had an $800 million 364-day credit agreement, which was restricted for the retirement of $800 million of 6.75% Senior Notes due March 1, 2006. On March 1, 2006, Progress Energy, Inc. retired $800 million of its 6.75% Senior Notes, thus effectively terminating the 364-day credit agreement.

On May 3, 2006, Progress Energy restructured its existing $1.13 billion five-year RCA with a syndication of financial institutions. The new RCA replaced an existing $1.13 billion five-year facility, which was terminated effective May 3, 2006. The new RCA will continue to be used to provide liquidity support for Progress Energy's issuances of commercial paper and other short-term obligations. The new RCA no longer includes a material adverse change representation for borrowings or a financial covenant for interest coverage. Fees and interest rates under the new RCA will continue to be determined 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.

On May 3, 2006, PEC's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa1 by Moody's and BBB- by S&P.

On May 3, 2006, PEF's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined 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.

We had no commercial paper outstanding or other short-term debt at December 31, 2006. The following table summarizes our outstanding commercial paper and other short-term debt and related weighted-average interest rates at December 31, 2005:

(in millions)		
PEC	4.65%	$ 73
PEF	4.75%	102
Total	4.71%	$ 175

The following table presents the aggregate maturities of long-term debt at December 31, 2006:

(in millions)	Progress Energy Consolidated	PEC	PEF
2007	$ 324	$ 200	$ 89
2008	877	300	532
2009	400	400	-
2010	406	6	300
2011	1,000	-	300
Thereafter	6,235	2,785	1,341
Total	$ 9,242	$ 3,691	$ 2,562

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, 2006, the maximum and calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio(a)
Progress Energy, Inc.	68%	55.4%
PEC	65%	52.3%
PEF	65%	49.4%

(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 could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. Progress Energy, Inc.'s cross-default provision applies only to Progress Energy, Inc. and its significant subsidiaries, as defined in the credit agreement, (i.e., PEC, Florida Progress Corporation (Florida Progress), PEF, Progress Capital Holdings, Inc. and PVI). PEC's and PEF's cross-default provisions apply only to 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, 2006, 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, 2006, 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, 2006, PEC's common stock equity was approximately 49.0 percent of total capitalization. At December 31, 2006, 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, 2006, 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, 2006, PEF's common stock equity was approximately 51.8 percent of total capitalization. At December 31, 2006, 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, 2006, PEC and PEF had a total of $2.869 billion and $1.871 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, 2006 and 2005, 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)	**2006**	2005	**2006**	2005	**2006**	2005
Nuclear decommissioning trust (See Note 5D)	$ **1,287**	$ 1,133	$ **735**	$ 640	$ **552**	$ 493
Investments in equity securities (a)	**6**	7	**4**	6	**1**	1
Equity method investments (b)	**23**	27	**13**	15	**-**	-
Cost investments (c)	**8**	13	**2**	1	**-**	-
Benefit investment trusts (d)	**80**	77	**2**	1	**-**	-
Company-owned life insurance (d)	**161**	153	**99**	97	**39**	39
Marketable debt securities (e)	**71**	191	**50**	191	**-**	-
Total	$ **1,636**	$ 1,601	$ **905**	$ 951	$ **592**	$ 533

(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.

(b) Investments in unconsolidated companies are included in the Consolidated Balance Sheets in miscellaneous other property and investments 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).

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

(d) 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.

(e) 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 $9.159 billion and $10.959 billion at December 31, 2006 and 2005, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $9.543 billion and $11.491 billion at December 31, 2006 and 2005, 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, 2006 and 2005 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

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**
2005			
(in millions)	Book Value	Unrealized	Estimated Fair Value
Equity securities	$ 406	$ 257	$ 663
Debt securities	673	7	680
Cash equivalents	18	-	18
Total	$ 1,097	$ 264	$ 1,361

At December 31, 2006, the fair value of available-for-sale debt securities by contractual maturity was (in millions):

Due in one year or less	$ 28
Due after one through five years	116
Due after five through 10 years	196
Due after 10 years	279
Total	$ 619

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)		2006		2005		2004
Proceeds	$	**2,547**	$	3,755	$	3,200
Realized gains		**33**		26		55
Realized losses		**24**		31		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, 2006 and 2005 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, 2006 and 2005 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 $3.670 billion and $3.667 billion at December 31, 2006 and 2005, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.732 billion and $3.789 billion at December 31, 2006 and 2005, 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, 2006 and 2005 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

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**
2005						
(in millions)		Book Value		Unrealized		Estimated Fair Value
Equity securities	$	218	$	141	$	359
Debt securities		461		4		465
Cash equivalents		10		-		10
Total	$	689	$	145	$	834

At December 31, 2006, the fair value of available-for-sale debt securities by contractual maturity was (in millions):

Due in one year or less	$ 18
Due after one through five years	80
Due after five through 10 years	76
Due after 10 years	197
Total	$ 371

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)	**2006**	2005	2004
Proceeds	**$ 995**	$ 1,678	$ 2,584
Realized gains	**21**	13	24
Realized losses	**14**	16	25

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, 2006 and 2005 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 $2.557 billion and $2.602 billion at December 31, 2006 and 2005, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $2.567 and $2.635 billion at December 31, 2006 and 2005, 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, 2006 and 2005 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

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**
2005			
(in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$ 188	$ 116	$ 304
Debt securities	180	3	183
Cash equivalents	5	-	5
Total	$ 373	$ 119	$ 492

At December 31, 2006, the fair value of available-for-sale debt securities by contractual maturity was (in millions):

Due in one year or less	$	3
Due after one through five years		26
Due after five through 10 years		100
Due after 10 years		61
Total	$	190

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)		**2006**		2005		2004
Proceeds	**$**	**509**	$	330	$	529
Realized gains		**12**		13		30
Realized losses		**9**		13		5

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, 2006 and 2005 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.

Progress Energy

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

(in millions)		2006		2005
Deferred income tax assets				
Asset retirement obligation liability	$	**141**	$	155
Compensation accruals		**99**		99
Deferred revenue		**28**		55
Derivative instruments		**42**		-
Environmental remediation liability		**36**		27
Income taxes refundable through future rates		**216**		234
Investments		**5**		-
SFAS No. 158, postretirement and pension benefits		**351**		274
Unbilled revenue		**36**		30
Other		**125**		108
Federal income tax credit carry forward		**851**		957
State net operating loss carry forward (net of federal expense)		**54**		44
Valuation allowance		**(71)**		(39)
Total deferred income tax assets		**1,913**		1,944
Deferred income tax liabilities				
Accumulated depreciation and property cost differences		**(1,349)**		(1,396)
Deferred fuel recovery		**(60)**		(89)
Deferred storm costs		**(51)**		(94)
Derivative instruments		**-**		(32)
Income taxes recoverable through future rates		**(436)**		(202)
Investments		**-**		(35)
Other		**(70)**		(64)
Total deferred income tax liabilities		**(1,966)**		(1,912)
Total net deferred income tax (liabilities) assets	$	**(53)**	$	32

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

(in millions)		2006		2005
Current deferred income tax assets	$	**159**	$	37
Noncurrent deferred income tax assets, included in other assets and deferred debits		**19**		79
Current deferred income tax liabilities, included in other current liabilities		**(1)**		(1)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities		**(230)**		(83)
Total net deferred income tax (liabilities) assets	$	**(53)**	$	32

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.

At December 31, 2006, the federal income tax credit carry forward includes $850 million of alternative minimum tax credits that do not expire and $1 million of general business credits that will expire during the period 2023 through 2025.

At December 31, 2006, we had gross state net operating loss carry forwards of $1.1 billion that will expire during the period 2009 through 2026.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We established additional valuation allowances of $32 million during 2006. 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.

We establish accruals for certain tax contingencies when, despite our belief that our tax return positions are fully supported, we believe that certain positions may be challenged and that it is probable our positions may not be fully sustained. We are under continuous examination by the IRS and other tax authorities, and we account 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, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

Considering all tax contingency reserves, we do not expect the resolution of these matters to have a material impact on our financial position or results of operations. The tax contingency reserves relate primarily to capitalization and basis issues.

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

	2006	2005	2004
Effective income tax rate	**28.1%**	(5.9)%	9.3%
State income taxes, net of federal benefit	**(6.5)**	(3.7)	(7.7)
Minority interest	**0.2**	(2.3)	(1.2)
Federal tax credits	**11.3**	43.7	30.2
Investment tax credit amortization	**1.7**	2.0	1.9
Employee stock ownership plan dividends	**1.7**	1.9	2.1
Domestic manufacturing deduction	**0.5**	1.3	-
Other differences, net	**(2.0)**	(2.0)	0.4
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Our effective income tax rate is favorably impacted by federal tax credits resulting from synthetic fuels production.

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

(in millions)	**2006**	2005	2004
Current - federal	**$ 377**	$ 382	$ 249
- state	**69**	78	71
Deferred - federal	**(136)**	(163)	(33)
- state	**(26)**	(36)	10
Valuation allowance	**14**	-	-
State net operating loss carry forward	**(3)**	(3)	(1)
Synthetic fuels tax credit	**(79)**	(282)	(215)
Investment tax credit	**(12)**	(13)	(14)
Total income tax expense (benefit)	**$ 204**	$ (37)	$ 67

Total income tax expense (benefit) 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 2006 or 2004.

- Taxes related to discontinued operations recorded net of tax for 2006, 2005 and 2004, which are presented separately in Notes 3A through 3G.

- Consolidated Statements of Comprehensive Income.

- Current tax benefit of $3 million related to excess tax deductions resulting from vesting of restricted stock, interim period vesting of stock-settled PSSP awards and exercises of nonqualified stock options, which was recorded in common stock during 2006. Current tax benefit of $2 million related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005. Less than $1 million was recorded in common stock for excess tax deductions during 2004.

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity that own facilities that produce synthetic fuels as defined under the Code. The production and sale of the synthetic fuels from these facilities qualifies for tax credits under Section 29/45K, if certain requirements are satisfied.

PEC

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

(in millions)		**2006**		2005
Deferred income tax assets:				
Asset retirement obligation liability	**$**	**132**	$	131
Compensation accruals		**47**		46
Deferred revenue		**28**		55
Income taxes refundable through future rates		**68**		54
SFAS No. 158, postretirement and pension benefits		**200**		155
Other		**37**		49
Federal income tax credit carry forward		**1**		20
Total deferred income tax assets		**513**		510
Deferred income tax liabilities:				
Accumulated depreciation and property cost differences		**(930)**		(952)
Deferred fuel recovery		**(55)**		(67)
Income taxes recoverable through future rates		**(317)**		(129)
Investments		**(10)**		(61)
Other		**(27)**		(27)
Total deferred income tax liabilities		**(1,339)**		(1,236)
Total net deferred income tax liabilities	**$**	**(826)**	$	(726)

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

(in millions)		**2006**		2005
Current deferred income tax assets, included in prepayments and other current assets	**$**	**34**	$	-
Current deferred income tax liabilities, included in other current liabilities		**-**		(4)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities		**(860)**		(722)
Total net deferred income tax liabilities	**$**	**(826)**	$	(726)

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, the federal income tax credit carry forward includes $1 million of general business credits that will expire during the period 2023 through 2025.

At December 31, 2006 and 2005, PEC had recorded $5 million and $2 million, respectively, of tax contingency reserves, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

Considering all tax contingency reserves, PEC does not expect the resolution of these matters to have a material impact on its financial position or results of operations. The tax contingency reserves relate primarily to capitalization and basis issues.

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

	2006	2005	2004
Effective income tax rate	**36.7%**	32.7%	34.1%
State income taxes, net of federal benefit	**(2.3)**	(2.1)	(2.9)
Investment tax credit amortization	**0.8**	1.1	1.1
Domestic manufacturing deduction	**0.6**	0.7	-
Progress Energy tax benefit allocation	**-**	2.9	3.0
Other differences, net	**(0.8)**	(0.3)	(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)	**2006**	2005	2004
Current - federal	**$ 285**	$ 343	$ 232
- state	**39**	45	33
Deferred - federal	**(42)**	(120)	(18)
- state	**(11)**	(21)	(1)
Investment tax credit	**(6)**	(8)	(7)
Total income tax expense	**$ 265**	$ 239	$ 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 2006 or 2004.

- Taxes related to other comprehensive income recorded net of tax for 2006, 2005 and 2004, which are presented separately in the Consolidated Statements of Comprehensive Income.

- Current tax benefit of $1 million related to excess tax deductions resulting from vesting of restricted stock, interim period vesting of stock-settled PSSP awards and exercises of nonqualified stock options, which was recorded in common stock during 2006. Current tax benefit of $1 million related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005. Less than $1 million was recorded in common stock for excess tax deductions during 2004.

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 $51 million and $74 million at December 31, 2006 and 2005, respectively.

PEF

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

(in millions)		2006		2005
Deferred income tax assets				
Asset retirement obligation liability	**$**	**9**	$	3
Derivative instruments		**30**		-
Environmental remediation liability		**24**		15
Income taxes refundable through future rates		**95**		123
SFAS No. 158, postretirement and pension benefits		**150**		85
Unbilled revenue		**36**		30
Other		**61**		53
Total deferred income tax assets		**405**		309
Deferred income tax liabilities				
Accumulated depreciation and property cost differences		**(429)**		(401)
Deferred fuel recovery		**(5)**		(21)
Deferred storm costs		**(45)**		(87)
Derivative instruments		**-**		(45)
Income taxes recoverable through future rates		**(119)**		(28)
Investments		**(61)**		(45)
Prepaid pension costs		**(67)**		(61)
Other		**(33)**		(25)
Total deferred income tax liabilities		**(759)**		(713)
Total net deferred income tax liabilities	**$**	**(354)**	$	(404)

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

(in millions)		2006		2005
Current deferred income tax assets	**$**	**86**	$	12
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities		**(440)**		(416)
Total net deferred income tax liabilities	**$**	**(354)**	$	(404)

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, excluding accrued interest and penalties, which were included in other current liabilities on the Balance Sheets.

Considering all tax contingency reserves, PEF does not expect the resolution of these matters to have a material impact on its financial position or results of operations. The tax contingency reserves relate primarily to capitalization and basis issues.
Reconciliations of PEF's effective income tax rate to the statutory federal income tax rate for the years ended December 31 follow:

	2006	2005	2004
Effective income tax rate	**37.0%**	31.8%	34.2%
State income taxes, net of federal benefit	**(3.6)**	(3.3)	(3.5)
Investment tax credit amortization	**1.2**	1.4	1.2
Domestic manufacturing deduction	**0.3**	0.9	-
Progress Energy tax allocation benefit	**-**	3.2	2.5
Other differences, net	**0.1**	1.0	0.6
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

(in millions)	**2006**	2005	2004
Current - federal	**$ 207**	$ 146	$ 55
- state	**34**	25	9
Deferred - federal	**(36)**	(39)	98
- state	**(6)**	(6)	18
Investment tax credit	**(6)**	(5)	(6)
Total income tax expense	**$ 193**	$ 121	$ 174

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 2006 or 2004.

- Taxes related to other comprehensive income recorded net of tax for 2006, 2005 and 2004, which are presented separately in the Statements of Comprehensive Income.

- Less than $1 million of current tax benefit related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2006, 2005 and 2004.

PEF has entered into the Tax Agreement with Progress Energy (See Note 1D). PEF's intercompany tax receivable was approximately $47 million at December 31, 2006. PEF's intercompany tax payable was approximately $7 million at December 31, 2005.

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 synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments, if any, would be based on the net after-tax cash flows the facilities generate. The CVO liability is adjusted to reflect market price fluctuations. The unrealized loss/gain recognized due to these market fluctuations is recorded in other, net on the Consolidated Statements of Income (See Note 20). The liability, included in other liabilities and deferred credits on the Consolidated Balance Sheets, at December 31, 2006 and 2005, was $32 million and $7 million, respectively.

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.

See Note 2 for information related to the implementation of SFAS No. 158 as of December 31, 2006.

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)	**2006**	2005	2004	**2006**	2005	2004
Service cost	**$ 45**	$ 47	$ 54	**$ 9**	$ 9	$ 12
Interest cost	**117**	117	110	**33**	33	31
Expected return on plan assets	**(148)**	(147)	(155)	**(6)**	(5)	(5)
Amortization of actuarial loss(a)	**18**	21	6	**4**	6	4
Other amortization, net (a)	**-**	-	(1)	**5**	5	3
Net periodic cost	**$ 32**	$ 38	$ 14	**$ 45**	$ 48	$ 45

(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.

No amounts related to our OPEB plans were recognized as a component of other comprehensive income (OCI) for the years ended December 31, 2006, 2005 and 2004. Pre-tax amounts related to our pension plans recognized as a component of OCI for the years ended December 31, 2006, 2005 and 2004 were net actuarial gains (losses) of $78 million, $(41) million and $(202) million, respectively.

PEC

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2006**	2005	2004	**2006**	2005	2004
Service cost	**$ 22**	$ 22	$ 24	**$ 4**	$ 4	$ 6
Interest cost	**52**	53	52	**17**	17	15
Expected return on plan assets	**(59)**	(62)	(69)	**(4)**	(4)	(4)
Amortization of actuarial loss	**11**	10	1	**2**	5	2
Other amortization, net	**1**	1	-	**1**	1	1
Net periodic cost	**$ 27**	$ 24	$ 8	**$ 20**	$ 23	$ 20

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 plan were recognized as a component of OCI for the years ended December 31, 2006, 2005 and

2004. Pre-tax amounts related to PEC's pension plans recognized as a component of OCI for the years ended December 31, 2006, 2005 and 2004, were net actuarial gains (losses) of $59 million, $(19) million and $(174) million, respectively.

PEF

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2006**	2005	2004	**2006**	2005	2004
Service cost	**$ 16**	$ 16	$ 21	**$ 3**	$ 3	$ 4
Interest cost	**49**	48	43	**14**	13	13
Expected return on plan assets	**(78)**	(73)	(73)	**(1)**	(1)	(1)
Amortization of actuarial loss	**3**	8	2	**1**	2	1
Other amortization, net	**(1)**	(1)	(1)	**4**	4	4
Net periodic (benefit) cost	**$ (11)**	$ (2)	$ (8)	**$ 21**	$ 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 plans were recognized as a component of OCI for the years ended December 31, 2006, 2005 and 2004. No amounts related to PEF's pension plans were recognized as a component of OCI for the years ended December 31, 2006 and 2005. For the year ended December 31, 2004, a pre-tax net actuarial gain of $6 million was recognized as a component of OCI.

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

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	**2006**	2005	2004
Discount rate	**5.65%**	5.70%	6.30%	**5.65%**	5.70%	6.30%
Rate of increase in future compensation						
Bargaining	**3.50%**	3.50%	3.50%	**-**	-	-
Supplementary plans	**5.25%**	5.25%	5.00%	**-**	-	-
Expected long-term rate of return on plan assets	**9.00%**	9.00%	9.25%	**8.30%**	8.25%	8.50%

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 PEF's OPEB plan assets was 5.0% 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 have chosen to use an expected long-term rate of 9.0%, the low end of the range, beginning in 2005.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

Reconciliations of the changes in the Progress Registrants' benefit obligations and the funded status as of December 31, 2006 and 2005 are presented in the tables below, with each table followed by related supplementary information.

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Projected benefit obligation at January 1	**$ 2,164**	$ 1,961	**$ 650**	$ 538
Service cost	**45**	47	**9**	9
Interest cost	**117**	117	**33**	33
Benefit payments	**(174)**	(182)	**(29)**	(33)
Plan amendment	**18**	-	**(4)**	-
Special termination benefits	**-**	123	**-**	19
Actuarial (gain) loss	**(47)**	98	**(31)**	84
Obligation at December 31	**2,123**	2,164	**628**	650
Fair value of plan assets at December 31	**1,836**	1,770	**74**	76
Funded status	**$ (287)**	$ (394)	**$ (554)**	$ (574)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.123 billion and $2.164 billion at December 31, 2006 and 2005, respectively. Those plans had accumulated benefit obligations totaling $2.083 billion and $2.117 billion at December 31, 2006 and 2005, respectively, and plan assets of $1.836 billion and $1.770 billion at December 31, 2006 and 2005, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Current liabilities	**$ 14**	$ -	**$ 1**	$ -
Noncurrent liabilities	**273**	347	**553**	390

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)	**2006**	2005	**2006**	2005
Recognized in accumulated other comprehensive loss				
Net actuarial loss	**$ 49**	$ 260	**$ 7**	$ -
Other, net	**5**	-	**1**	-
Recognized in regulatory assets, net				
Net actuarial loss (gain)	**215**	83	**108**	(19)
Other, net	**22**	-	**28**	24
Recognized as an intangible asset				
Prior service cost	**-**	23	**-**	-
Not recognized in the Consolidated Balance Sheets				
Net actuarial loss	**-**	47	**-**	170
Other, net	**-**	-	**-**	14
Total not yet recognized as a component of net periodic cost(a)	**$ 291**	$ 413	**$ 144**	$ 189

(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 2007.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss [(a)]	$ 15	$ 6
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)	**2006**	2005	**2006**	2005
Projected benefit obligation at January 1	**$ 969**	$ 928	**$ 333**	$ 262
Service cost	**22**	22	**4**	4
Interest cost	**52**	53	**17**	17
Plan amendment	**9**	-	**-**	-
Benefit payments	**(83)**	(94)	**(11)**	(14)
Actuarial (gain) loss	**(17)**	39	**(13)**	56
Special termination benefits	**-**	21	**-**	8
Obligation at December 31	**952**	969	**330**	333
Fair value of plan assets at December 31	**741**	731	**45**	49
Funded status	**$ (211)**	$ (238)	**$ (285)**	$ (284)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $952 million and $969 million at December 31, 2006 and 2005, respectively. Those plans had accumulated benefit obligations totaling $946 million and $963 million at December 31, 2006 and 2005, respectively, and plan assets of $741 million and $731 million at December 31, 2006 and 2005, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Current liabilities	**$ 2**	$ -	**$ -**	$ -
Noncurrent liabilities	**209**	232	**285**	189

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)	**2006**	2005	**2006**	2005
Recognized in accumulated other comprehensive loss				
Net actuarial loss	**$ -**	$ 195	**$ -**	$ -
Recognized as an intangible asset				
Prior service cost	**-**	17	**-**	-
Recognized in regulatory assets				
Net actuarial loss	**142**	-	**69**	-
Other, net	**25**	-	**7**	-
Not recognized in the Consolidated Balance Sheets				
Net actuarial loss	**-**	6	**-**	87
Other, net	**-**	-	**-**	8
Total not yet recognized as a component of net periodic cost	**$ 167**	$ 218	**$ 76**	$ 95

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2007.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	**$ 11**	**$ 4**
Amortization of other, net	**2**	**1**

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Projected benefit obligation at January 1	**$ 896**	$ 767	**$ 259**	$ 232
Service cost	**16**	16	**3**	3
Interest cost	**49**	48	**14**	13
Plan amendment	**8**	-	**(4)**	-
Benefit payments	**(69)**	(61)	**(17)**	(18)
Special termination benefits	**-**	85	**-**	7
Actuarial (gain) loss	**(20)**	41	**(9)**	22
Obligation at December 31	**880**	896	**246**	259
Fair value of plan assets at December 31	**952**	895	**24**	22
Funded status	**$ 72**	$ (1)	**$ (222)**	$ (237)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $342 million and $341 million at December 31, 2006 and 2005, respectively. Those plans had accumulated benefit obligations totaling $311 million and $306 million at December 31, 2006 and 2005, respectively, and plan assets of $240 million and $217 million at December 31, 2006 and 2005, respectively. The total accumulated benefit obligation for pension plans was $849 million and $860 million at December 31, 2006 and 2005, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Noncurrent assets	**$ 174**	$ 200	**$ -**	$ -
Current liabilities	**3**	-	**-**	-
Noncurrent liabilities	**99**	89	**222**	159

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)	**2006**	2005	**2006**	2005
Recognized as an intangible asset				
Prior service cost	**$ -**	$ 1	**$ -**	$ -
Recognized in regulatory assets, net				
Net actuarial loss	**72**	7	**39**	-
Other, net	**(2)**	-	**21**	-
Not recognized in the Balance Sheets				
Net actuarial loss	**-**	125	**-**	49
Other, net	**-**	(13)	**-**	29
Total not yet recognized as a component of net periodic cost	**$ 70**	$ 120	**$ 60**	$ 78

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2007.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	**$ 1**	**$ 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	
	2006	2005	**2006**	2005
Discount rate	**5.95%**	5.65%	**5.95%**	5.65%
Rate of increase in future compensation				
Bargaining	**4.25%**	3.50%	**-**	-
Supplementary plans	**5.25%**	5.25%	**-**	-
Initial medical cost trend rate for pre-Medicare Act benefits	**-**	-	**9.00%**	8.25%
Initial medical cost trend rate for post-Medicare Act benefits	**-**	-	**9.00%**	8.25%
Ultimate medical cost trend rate	**-**	-	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	**-**	-	**2014**	2013

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	29	15	11
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(1)	(1)	(1)
Effect on postretirement benefit obligation	(22)	(12)	(9)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, substantially all 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 10 percent for PEF. The OPEB benefits payments for 2006 are also reduced by prescription drug-related federal subsidies received, which 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)	**2006**	2005	**2006**	2005
Fair value of plan assets at January 1	**$ 1,770**	$ 1,774	**$ 76**	$ 70
Actual return on plan assets	**222**	170	**8**	5
Benefit payments	**(174)**	(182)	**(29)**	(33)
Employer contributions	**18**	8	**19**	34
Fair value of plan assets at December 31	**$ 1,836**	$ 1,770	**$ 74**	$ 76

PEC	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Fair value of plan assets at January 1	**$ 731**	$ 753	**$ 49**	$ 45
Actual return on plan assets	**91**	71	**6**	4
Benefit payments	**(83)**	(94)	**(11)**	(14)
Employer contributions	**2**	1	**1**	14
Fair value of plan assets at December 31	**$ 741**	$ 731	**$ 45**	$ 49

PEF	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Fair value of plan assets at January 1	**$ 895**	$ 868	**$ 22**	$ 20
Actual return on plan assets	**114**	85	**1**	-
Benefit payments	**(69)**	(61)	**(17)**	(18)
Employer contributions	**12**	3	**18**	20
Fair value of plan assets at December 31	**$ 952**	$ 895	**$ 24**	$ 22

The asset allocation for the benefit plans at the end of 2006 and 2005 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	2007	**2006**	2005
Equity - domestic	40%	**44%**	44%
Equity - international	15%	**23%**	22%
Debt - domestic	20%	**12%**	13%
Debt - international	10%	**9%**	8%
Other	15%	**12%**	13%
Total	100%	**100%**	100%

Other Postretirement Benefits

Progress Energy	Target Allocations	Percentage of Plan Assets	
Asset Category	2007	**2006**	2005
Equity - domestic	27%	**30%**	32%
Equity - international	10%	**15%**	16%
Debt - domestic	46%	**40%**	37%
Debt - international	7%	**7%**	6%
Other	10%	**8%**	9%
Total	100%	**100%**	100%

PEC	Target Allocations	Percentage of Plan Assets	
Asset Category	2007	**2006**	2005
Equity - domestic	40%	**44%**	44%
Equity - international	15%	**23%**	22%
Debt - domestic	20%	**12%**	13%
Debt - international	10%	**9%**	8%
Other	15%	**12%**	13%
Total	100%	**100%**	100%

PEF	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2007	**2006**	2005
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 five 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 2007, we expect to make $60 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 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $143, $147, $151, $154, $154 and $838, respectively. The expected benefit payments for the OPEB plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $41, $45, $48, $51, $53 and $284, 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 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $3, $4, $4, $5, $5 and $38, respectively.

In 2007, PEC expects to make $35 million in contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $69, $72, $74, $76, $75 and $399, respectively. The expected benefit payments for the OPEB plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $19, $21, $23, $25, $27, and $148, 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 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $1, $2, $2, $2, $3 and $19, respectively.

In 2007, PEF expects to make $10 million of contributions directly to pension plan assets and $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $56, $56, $57, $57, $59 and $316, respectively. The expected benefit payments for the OPEB plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $19, $20, $21, $22, $22 and $113, 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 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $2, $2, $2, $2, $2 and $16, 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 3, on December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of PVI's remaining CCO physical and commercial assets and on July 12, 2006, our board of directors approved a plan to divest of Gas. The transaction to sell Gas closed on October 2, 2006. We expect to complete the disposition plan for CCO in 2007.

Due to the reclassification of the remaining CCO operations to discontinued operations in December 2006, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 Bcf of natural gas would be fulfilled. Therefore, these contracts were no longer treated as cash flow hedges, and were dedesignated and cash flow hedge accounting was discontinued.

At December 31, 2006, derivative assets and derivative liabilities related to CCO are included in assets of discontinued operations and liabilities of discontinued operations, respectively, on the Consolidated Balance Sheet. At December 31, 2005, derivative assets and derivative liabilities related to Gas and CCO are included in assets of discontinued operations and liabilities of discontinued operations, respectively, on the Consolidated Balance Sheet. For the years ending December 31, 2006, 2005 and 2004, 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 ending 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 ending December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges. For the year ending December 31, 2004, discontinued operations, net of tax includes $10 million in after-tax deferred losses, which were reclassified to earnings due to discontinuance of the related cash flow hedges.

A. Commodity Derivatives

GENERAL

Most of our 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, 2006 and 2005, the remaining liability was $14 million and $19 million, respectively.

ECONOMIC DERIVATIVES

Derivative products, primarily electricity and natural gas 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. Gains and losses from such contracts were not material to our or the Utilities' results of operations during the years ended December 31, 2006, 2005 and 2004. Excluding $107 million of derivative assets, which are included in assets of discontinued operations on the Consolidated Balance Sheet and $31 million of derivative liabilities, which are included in liabilities of discontinued operations on the Consolidated Balance Sheet at December 31, 2006, we did not have material outstanding positions in such contracts at December 31, 2006 and 2005, other than those receiving regulatory accounting treatment at PEF, as discussed below. Our discontinued operations did not have material outstanding positions in such contracts at December 31, 2005.

PEC did not have material outstanding positions in such contracts at December 31, 2006 and 2005. PEF did not have material outstanding positions in such contracts at December 31, 2006 and 2005, other than those receiving regulatory accounting treatment, as discussed below.

PEF has derivative instruments related to its 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. Once settled, any realized gains or losses are passed through the fuel clause. At December 31, 2006, the fair values of these instruments were a $2 million long-term derivative asset position included in other assets and deferred debits, 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 Balance Sheet. At December 31, 2005, the fair values of the instruments were a $77 million short-term derivative asset position included in other current assets, a $45 million long-term derivative asset position included in other assets and deferred debits and a $49 million long-term derivative liability position included in other liabilities and deferred credits on the Balance Sheet.

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 is 25 million barrels and will provide protection for the equivalent of approximately eight million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts will be marked-to-market with changes in fair value recorded through earnings from synthetic fuels production.

CASH FLOW HEDGES

Our subsidiaries designate 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 natural gas and power for our forecasted purchases and sales. Realized gains and losses are recorded net in operating revenues or operating expenses, as appropriate. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities' results of operations for 2006, 2005 and 2004.

The fair values of commodity cash flow hedges at December 31 were as follows:

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Fair value of assets	$ **2**	$ 7	$ **2**	$ 7	$ **-**	$ -
Fair value of liabilities	**-**	(4)	**-**	(4)	**-**	-
Fair value, net	$ **2**	$ 3	$ **2**	$ 3	$ **-**	$ -

Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. Excluded from the table above are $163 million of derivative assets, which are included in assets of discontinued operations, and $54 million of derivative liabilities, which are included in liabilities of discontinued operations on the Consolidated Balance Sheet at December 31, 2005.

At December 31, 2006, the amount recorded in our, PEC's or PEF's AOCI related to commodity cash flow hedges was not material. At December 31, 2005, we had $69 million of after-tax deferred income and PEC had $2 million of after-tax deferred income recorded in AOCI related to commodity cash flow hedges. PEF had no amount recorded in AOCI related to commodity cash flow hedges at December 31, 2006 or 2005.

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 risk in these transactions is the cost of replacing the agreements at current market rates.

On November 7, 2006, Progress Energy commenced a tender offer for up to $550 million aggregate principal amount of its 2011 and 2012 senior notes. Subsequently, we executed a total notional amount of $550 million of reverse treasury locks to reduce exposure to changes in cash flow due to fluctuating interest rates, which were then terminated on December 1, 2006. On December 6, 2006, Progress Energy repurchased, pursuant to the tender offer, $550 million, or 53.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest.

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

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Interest rate cash flow hedges	$ **(2)**	$ 1	$ **(1)**	$ -	$ **(1)**	$ -
Interest rate fair value hedges	**(1)**	(2)	-	-	-	-

CASH FLOW HEDGES

Gains and losses from cash flow hedges are recorded in AOCI and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. Amounts in AOCI 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 2006, 2005 and 2004.

The following table presents selected information related to interest rate cash flow hedges included in AOCI at December 31, 2006:

	Maximum Term			Accumulated Other Comprehensive Loss, net of Tax (a)			Portion Expected to be Reclassified to Earnings during the Next 12 Months (b)		
(term in years/ dollars in millions)	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF
Interest rate cash flow hedges	1	1	1	$ (14)	$ (5)	$ (1)	$ (2)	$ (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.

PEC entered into a $50 million forward starting swap on June 2, 2006, and PEF entered into a $50 million forward starting swap on June 6, 2006, to mitigate exposure to interest rate risk on their respective anticipated debt issuances in 2007. These swaps were designated as cash flow hedges as of July 1, 2006.

At December 31, 2005, including amounts related to terminated hedges, we had $13 million of after-tax deferred losses and PEC had $5 million of after-tax deferred losses recorded in AOCI related to interest rate cash flow hedges. PEF had no amount recorded in AOCI related to interest rate cash flow hedges.

At December 31, 2005, we had $100 million notional of interest rate cash flow hedges, which were settled in the first quarter of 2006. The Utilities had no open interest rate cash flow hedges at December 31, 2005.

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, 2006 and 2005, we had $50 million notional and $150 million notional, respectively, of interest rate fair value hedges. At December 31, 2006 and 2005, 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, tolling 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, 2006, the Parent had issued $1.34 billion 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 2006, 2005 and 2004 to PEC amounted to $188 million, $202 million and $209 million, respectively, and services provided to PEF were $165 million, $169 million and $165 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2006, 2005 and 2004 amounted to $34 million, $54 million and $52 million, respectively. Services provided by PEF to PEC during 2006, 2005 and 2004 amounted to $8 million, $14 million and $16 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 5.17%, 3.77% and 1.72% at December 31, 2006, 2005 and 2004, 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 2006 and for an insignificant profit in 2005 and 2004. 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 $321 million, $402 million and $331 million for the years ended December 31, 2006, 2005 and 2004, 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 segments are: PEC, PEF, and Coal and Synthetic Fuels.

Our 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.

Our Coal and Synthetic Fuels segment is 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. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding synthetic fuels production. During September and October 2006, we resumed limited synthetic fuels production at our facilities, which continued through the end of 2006. See Notes 8 and 9 for additional information.

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC as well as other nonregulated businesses. These nonregulated businesses do not separately meet the disclosure requirements of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." Included in the 2004 losses is a $43 million pre-tax ($29 million after-tax) settlement agreement that our subsidiary Strategic Resource Solutions Corp. reached with the San Francisco United School District related to civil proceedings. The profit or loss of our reportable segments plus the profit or loss of Corporate and Other represents our total income from continuing operations.

As discussed in Note 3, prior to 2006, our former Progress Ventures segment was engaged in nonregulated electric generation and energy marketing activities and natural gas drilling and production. Also, prior to 2006, PT LLC was included within the Corporate and Other segment, and Dixie Fuels and other fuels business were included within the Coal and Synthetic Fuels segment. In connection with their respective divestitures, certain of which are expected to close in 2007, these operations were reclassified to discontinued operations in 2006 and therefore are not included in the results from continuing operations during the periods reported. 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.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between PEF and the 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 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 2006, 2005 and 2004 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 of discontinued operations are not included in the table presented below.

(in millions)	PEC	PEF	Coal and Synthetic Fuels	Corporate	Eliminations	Totals
As of and for the year ended December 31, 2006						
Revenues						
Unaffiliated	$ 4,086	$ 4,639	$ 845	$ -	$ -	$ 9,570
Intersegment	-	-	321	408	(729)	-
Total revenues	4,086	4,639	1,166	408	(729)	9,570
Depreciation and amortization	571	404	19	38	-	1,032
Interest income	25	15	2	85	(66)	61
Total interest charges, net	215	150	15	312	(67)	625
Impairment of long-lived assets and investments	-	-	91	-	-	91
Income tax expense (benefit)	265	193	(145)	(109)	-	204
Segment profit (loss)	454	326	(76)	(190)	-	514
Total assets	12,020	8,593	268	15,204	(11,271)	24,814
Capital and investment expenditures	808	741	3	12	(9)	1,555

As of and for the year ended December 31, 2005						
Revenues						
Unaffiliated	$ 3,991	$ 3,955	$ 1,222	$ -	$ -	$ 9,168
Intersegment	-	-	402	437	(839)	-
Total revenues	3,991	3,955	1,624	437	(839)	9,168
Depreciation and amortization	561	334	34	34	-	963
Interest income	8	1	3	94	(90)	16
Total interest charges, net	192	126	23	318	(85)	574
Postretirement and severance charges	55	102	5	1	-	163
Income tax expense (benefit)	239	121	(354)	(43)	-	(37)
Segment profit (loss)	490	258	163	(190)	-	721
Total assets	11,502	8,318	450	17,898	(13,672)	24,496
Capital and investment expenditures	682	543	5	19	(19)	1,230

(in millions)	PEC	PEF	Coal and Synthetic Fuels	Corporate	Eliminations	Totals
As of and for the year ended December 31, 2004						
Revenues						
Unaffiliated	$ 3,629	$ 3,525	$ 886	$ 13	$ -	$ 8,053
Intersegment	-	-	333	430	(763)	-
Total revenues	3,629	3,525	1,219	443	(763)	8,053
Depreciation and amortization	570	281	34	34	-	919
Interest income	4	-	6	90	(89)	11
Total interest charges, net	192	114	23	322	(85)	566
Postretirement and severance charges	2	-	1	-	-	3
Income tax expense (benefit)	239	174	(280)	(66)	-	67
Segment profit (loss)	458	333	90	(208)	-	673
Total assets	10,787	7,924	540	17,465	(13,550)	23,166
Capital and investment expenditures	620	492	6	20	(12)	1,126

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income, impairment of investments, 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)		2006		2005		2004
Other income						
Nonregulated energy and delivery services income	$	**41**	$	32	$	28
DIG Issue C20 amortization (Note 17A)		**5**		7		9
Contingent value obligation unrealized gain (Note 15)		**-**		6		9
Gain on sale of Level 3 stock [(a)]		**32**		-		-
Investment gains		**4**		4		2
Income from equity investments		**1**		1		3
AFUDC equity		**21**		16		12
Reversal of indemnification liability (Note 21B)		**29**		-		-
Other		**16**		16		14
Total other income		**149**		82		77
Other expense						
Nonregulated energy and delivery services expenses		**27**		23		21
Donations		**20**		18		15
Contingent value obligation unrealized loss (Note 15)		**25**		-		-
Loss from equity investments		**8**		13		8
Loss on debt redemption[(b)]		**59**		-		-
FERC audit settlement		**-**		7		-
Indemnification liability (Note 21B)		**13**		16		-
Other		**15**		12		29
Total other expense		**167**		89		73
Other, net - Progress Energy	$	**(18)**	$	(7)	$	4

PEC

(in millions)		2006		2005		2004
Other income						
Nonregulated energy and delivery services income	$	**15**	$	12	$	11
DIG Issue C20 amortization (Note 17A)		**5**		7		9
Income from equity investments		**-**		1		3
AFUDC equity		**4**		3		4
Reversal of indemnification liability (Note 21B)		**29**		-		-
Other		**10**		9		13
Total other income		**63**		32		40
Other expense						
Nonregulated energy and delivery services expenses		**7**		9		9
Donations		**10**		8		7
Losses from equity investments		**1**		-		3
FERC audit settlement		**-**		4		-
Indemnification liability (Note 21B)		**13**		16		-
Other		**7**		10		22
Total other expense		**38**		47		41
Other, net - PEC	$	**25**	$	(15)	$	(1)

PEF

(in millions)		2006		2005		2004
Other income						
Nonregulated energy and delivery services income	$	**26**	$	20	$	17
Investment gains		**2**		2		1
AFUDC equity		**17**		13		7
Other		**1**		-		-
Total other income		**46**		35		25
Other expense						
Nonregulated energy and delivery services expenses		**20**		14		12
Donations		**10**		10		9
Losses from equity investments		**1**		-		-
FERC audit settlement		**-**		3		-
Other		**2**		1		1
Total other expense		**33**		28		22
Other, net - PEF	$	**13**	$	7	$	3

(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 3D). 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 53.0 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 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 or the state of Florida, 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 potentially responsible parties (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 potential 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)	2006	2005
PEC		
MGP and other sites[a]	$ 22	$ 7
PEF		
Remediation of distribution and substation transformers	43	20
MGP and other sites	18	18
Total PEF environmental remediation accruals[b]	61	38
Progress Energy nonregulated operations	3	3
Total Progress Energy environmental remediation accruals	$ 86	$ 48

(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 and 2005, the remaining accrual balance was approximately $3 million. Expenditures related to this liability were not material during 2006 and 2005.

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, 2006, including the Ward Transformer site and MGP sites discussed below, PEC accrued approximately $21 million and spent approximately $6 million. For the year ended December 31, 2005, PEC accrued approximately $4 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 (See Note 7B).

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 $32 million. In May 2006, a meeting was called by the EPA to discuss a settlement proposal among the PRPs. An agreement among PRPs has not been reached; consequently, it is not possible at this time to reasonably estimate the amount of PEC's share of the reimbursement for remediation of the Carolina Transformer site. The outcome of this matter cannot be predicted.

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 EPA's past expenditures in addressing conditions at the site. In September 2005, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the site. For the year ended December 31, 2005, PEC accrued approximately $3 million for its portion of the EPA's estimated remediation costs and the EPA's past costs. 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. 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.

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. However, 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.

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 years ended December 31, 2006 and 2005, PEF accrued approximately $42 million and $2 million, respectively, due to additional sites expected to require remediation and spent approximately $19 million and $9 million, respectively, related to the remediation of transformers. At December 31, 2006, 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, 2006, PEF made no accruals and PEF's expenditures and insurance proceeds were not material to our or PEF's results of operations or financial condition. For the year ended December 31, 2005, PEF made no material accruals, spent approximately $1 million and received approximately $1 million of additional insurance proceeds.

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 Mercury Rule (CAMR), the Clean Air Visibility Rule (CAVR), the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) and the Clean Smokestacks Act. At December 31, 2006, cumulative capital expenditures to date to comply with these environmental laws and regulations were $937 million, including $909 million and $28 million at PEC and PEF, respectively.

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide (NOx) and SO_2 from their North Carolina coal-fired power plants in phases by 2013. The Clean Smokestacks Act requires PEC to amortize $569 million, representing 70 percent of the original cost estimate of $813 million, during the five-year period ending December 31, 2007. The Clean Smokestacks Act permits PEC the flexibility to vary the amortization schedule for recording of the compliance costs from none up to $174 million per year. For the years ended December 31, 2006, 2005 and 2004, PEC recognized amortization of $140 million, $147 million and $174 million, respectively, and has recognized $535 million in cumulative amortization through December 31, 2006. The remaining amortization requirement of $34 million will be recorded during the one-year period ending December 31, 2007. The NCUC will hold a hearing prior to December 31, 2007, to determine cost-recovery amounts for 2008 and 2009.

Two of PEC's largest coal-fired generation plants (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 on 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, 2006, the amount of the liability was $29 million and had increased from $16 million at December 31, 2005, based upon the respective current estimates for Clean Smokestacks Act compliance. Because PEC has taken a systemwide compliance approach, its North Carolina retail customers 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 customers, consistent with other capital expenditures associated with PEC's compliance with the Clean Smokestacks Act. On November 2, 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 subsequently reclassified $29 million of indemnification expense to Clean Smokestacks Act amortization (See Note 20).

22. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2006, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2007	2008	2009	2010	2011	Thereafter
Fuel	$ 2,128	$ 1,514	$ 1,057	$ 509	$ 390	$ 1,251
Purchased power	485	454	422	377	381	4,165
Construction obligations	393	197	8	3	-	-
Other purchase obligations	86	71	23	22	15	74
Total	$ 3,092	$ 2,236	$ 1,510	$ 911	$ 786	$ 5,490

PEC

(in millions)	2007	2008	2009	2010	2011	Thereafter
Fuel	$ 1,008	$ 759	$ 547	$ 314	$ 231	$ 647
Purchased power	129	87	85	43	44	464
Construction obligations	99	9	-	-	-	-
Other purchase obligations	21	22	3	3	3	12
Total	$ 1,257	$ 877	$ 635	$ 360	$ 278	$ 1,123

PEF

(in millions)	2007	2008	2009	2010	2011	Thereafter
Fuel	$ 931	$ 682	$ 511	$ 194	$ 160	$ 605
Purchased power	356	366	336	334	337	3,701
Construction obligations	294	188	8	3	-	-
Other purchase obligations	46	46	20	19	12	62
Total	$ 1,627	$ 1,282	$ 875	$ 550	$ 509	$ 4,368

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 $3.168 billion, $3.071 billion and $2.033 billion for 2006, 2005 and 2004, respectively. PEC's total payments under these commitments for its generating plants were $1.051 billion, $964 million and $477 million in 2006, 2005 and 2004, respectively. PEF's payments totaled $577 million, $506 million and $375 million in 2006, 2005 and 2004, respectively.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (primarily QFs) with expiration dates ranging from 2007 to 2033. These purchased power contracts generally provide for capacity and energy payments.

Pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between PEC and Power Agency, PEC is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, Harris. In 1993, PEC and Power Agency entered into an agreement to restructure portions of their contracts covering power supplies and interests in jointly owned units. Under the terms of the 1993 agreement, PEC increased the amount of capacity and energy purchased from Power Agency's ownership interest in Harris, and the buyback period was extended six years through 2007. The estimated minimum annual payments for these purchases, which reflect capacity and energy costs, total approximately $34 million. These contractual purchases totaled $38 million, $37 million and $39 million for 2006, 2005 and 2004, respectively.

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 $80 million, $71 million and $62 million for 2006, 2005 and 2004, 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 $40 million, $44 million and $42 million in 2006, 2005 and 2004, respectively.

PEC has various pay-for-performance contracts with QFs for approximately 327 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 $182 million, $112 million and $90 million in 2006, 2005 and 2004, 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 $162 million, $175 million and $128 million for 2006, 2005 and 2004, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $65 million annually through 2009, $54 million for 2010 and $38 million annually thereafter through 2016.

PEF has ongoing purchased power contracts with certain QFs for 943 MW of capacity with expiration dates ranging from 2007 to 2033. 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 have been approved by the FPSC. Total capacity purchases under these contracts amounted to $277 million, $262 million and $247 million for 2006, 2005 and 2004, respectively. At December 31, 2006, minimum expected future capacity payments under these contracts were $289 million, $300 million, $271 million, $274 million and $288 million for 2007 through 2011, respectively, and $3.508 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.

On December 2, 2004, PEF entered into precedent and related agreements with Southern Natural Gas Company (SNG), Florida Gas Transmission Company (FGT), and BG LNG Services, LLC for the supply of natural gas and associated firm pipeline transportation to augment PEF's gas supply needs for the period from May 1, 2007, to April 30, 2027. The total cost to PEF associated with the agreements is approximately $3.9 billion. The transactions are subject to several conditions precedent, some of which have been satisfied, which include obtaining the FPSC's approval of the agreements, the completion and commencement of operation of the necessary related expansions to SNG's and FGT's respective natural gas pipeline systems, and other standard closing conditions. Due to the conditions in the agreements, the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

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 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 $877 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 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 Florida Public Service Commission 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 May 31, 2013. The total cost to PEF associated with this agreement is approximately $128 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.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $365 million, $91 million and $108 million for 2006, 2005 and 2004, respectively. At December 31, 2006, PEC had construction obligations related to Clean Smokestacks Act capital projects of $99 million and $9 million for 2007 and 2008, respectively, and none thereafter. Total purchases by PEC under various capital projects related to Clean Smokestacks Act were $225 million for 2006 and purchases under various combustion turbine construction obligations were $5 million for 2004. PEC did not have any purchases related to construction obligations in 2005. PEF has purchase obligations related to various plant capital projects related to new generation and Florida CAIR. Total payments under PEF's contracts were $140 million, $91 million and $102 million for 2006, 2005 and 2004, respectively. PEF's future obligations under these contracts are $294 million, $188 million, $8 million and $3 million for 2007 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 $91 million, $82 million and $44 million for 2006, 2005 and 2004, 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 $18 million, $17 million and $15 million for 2006, 2005 and 2004, respectively. Estimated future payments under these contracts of $198 million are not reflected in the table presented at the beginning of this footnote. Included in these contracts are purchase obligations with two counterparties for pipeline capacity through 2018 and 2028. Payments under these agreements were $16 million, $15 million and $13 million for 2006, 2005 and 2004, respectively. Future obligations under these contracts are approximately $13 million for 2007, $12 million for 2008 through 2011 and approximately $76 million payable thereafter. We anticipate transferring the obligations under these contracts to a third party as part of our disposition strategy.

PEC has various purchase obligations for emission obligations, limestone supply and the purchase of capital parts. Total purchases under these contracts were $2 million, $10 million and $2 million for 2006, 2005 and 2004, respectively. Future obligations under these contracts are $21 million each for 2007 and 2008, $3 million each for 2009 through 2011 and $12 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, $13 million for 2005 and $17 million for 2004. We do not have any future purchase obligations under these contracts.

PEF has long-term service agreements for the Hines Energy Complex. Total payments under these contracts were $12 million, $8 million and $11 million for 2006, 2005 and 2004, respectively. Future obligations under these contracts are $11 million, $16 million, $14 million, $19 million and $12 million for 2007 through 2011, respectively, with approximately $62 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 $21 million for 2006 and $34 million for 2005. There were no payments under these contracts during 2004. Future obligations under these contracts are $22 million, $8 million and $6 million for 2007 through 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 $42 million for 2006 and $38 million each for 2005 and 2004. Our purchased power expense under agreements classified as operating leases was approximately $60 million, $14 million and $25 million in 2006, 2005 and 2004, respectively.

PEC's rent expense under operating leases totaled $25 million for 2006, $24 million for 2005 and $20 million for 2004. These amounts include rent expense allocated from PESC of $8 million, $7 million and $10 million for 2006, 2005 and 2004, respectively. Purchased power expense under agreements classified as operating leases were approximately $10 million, $11 million and $25 million in 2006, 2005 and 2004, respectively.

PEF's rent expense under operating leases totaled $16 million, $11 million and $14 million during 2006, 2005 and 2004, respectively. These amounts include rent expense allocated from PESC to PEF of $7 million each for 2006 and 2005 and $10 million for 2004. Purchased power expense under agreements classified as operating leases was approximately $49 million and $3 million in 2006 and 2005, respectively, and none in 2004.

Assets recorded under capital leases at December 31 consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Buildings	**$ 84**	$ 30	**$ 30**	$ 30	**$ 54**	$ -
Less: Accumulated amortization	**(12)**	(12)	**(12)**	(12)	**-**	-
Total	**$ 72**	$ 18	**$ 18**	$ 18	**$ 54**	$ -

At December 31, 2006, 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
2007	$ 6	$ 79	$ 2	$ 36	$ 4	$ 39
2008	8	63	3	30	5	29
2009	7	55	2	30	5	22
2010	8	40	3	18	5	20
2011	7	19	2	13	5	4
Thereafter	91	172	12	142	79	26
Minimum annual payments	127	$ 428	24	$ 269	103	$ 140
Less amount representing imputed interest	(55)		(6)		(49)	
Present value of net minimum lease payments under capital leases	$ 72		$ 18		$ 54	

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 2005, PEF entered into an agreement for a new 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. Due to the conditions of the agreement, the capital lease will not be recorded on PEF's Balance Sheet until 2007. Therefore this capital lease is not included in the table above. The agreement calls for annual payments of approximately $27 million from 2007 through 2024 for a total of approximately $460 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 $9 million, $7 million, $6 million, $4 million and $2 million for 2007 through 2011, respectively. Rents received under these operating leases totaled $9 million, $8 million and $6 million for 2006, 2005 and 2004, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals under noncancelable leases are $10 million for 2007 and none thereafter. PEC's rents received are contingent upon usage and totaled $31 million each for 2006 and 2005 and $32 million for 2004. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $72 million for 2006 and $63 million each for 2005 and 2004. PEF's minimum rentals under noncancelable leases are not material for 2007 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." These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes (See Note 18). Our guarantees include performance obligations under power supply agreements, tolling 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, 2006, 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, 2006, we have issued guarantees and indemnifications of 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. 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 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, 2006, the maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $208 million, including $32 million at PEF. At December 31, 2006 and 2005, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $60 million and $41 million, respectively. These amounts include $29 million and $16 million, respectively, for PEC at December 31, 2006 and 2005, and $8 million for PEF at December 31, 2006. PEF had no liabilities related to guarantees and indemnifications to third parties at December 31, 2005. 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

1. 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 or are expected to be presented in the trials or appeals that are currently scheduled to occur 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 has commenced. The trial court's scheduling order, issued on March 23, 2006, included an anticipated trial date in late 2007.

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 EPA is expected to issue a new safety standard for the repository in early 2007. 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 has since reported that the license application will be submitted by June 2008. Congress approved $450 million for fiscal year 2006 for the Yucca Mountain project, approximately $201 million less than requested by the DOE. The DOE requested $545 million for fiscal year 2007. The request has not been approved at this time and the DOE is operating under a continuing resolution that limits spending to the level of fiscal year 2006.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 onsite 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.

2. 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 that (1) 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 and (2) it is entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities.

The first suit, *U.S. Global, LLC v. Progress Energy, Inc. et al.*, asserts the above claims in a case filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case), 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*, 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 (the North Carolina Global Case). 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 during the course of the Internal Revenue Service (IRS) audit of the Earthco synthetic fuels facilities. The audit was successfully resolved in 2006 and the escrow, which totaled $42 million at December 31, 2006, was paid to Global in January 2007. The remainder of the suit continues. We cannot predict the outcome of this matter.

3. 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, 2006, 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 CCO, Gas, PT LLC, DeSoto, Rowan, Dixie Fuels and other fuels businesses as discontinued operations as described in Note 3.

Condensed Consolidating Statement of Income
Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ -	$ 4,637	$ 4,085	$ 8,722
Diversified business	-	839	9	848
Total operating revenues	-	5,476	4,094	9,570
Operating expenses				
Utility				
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	-	404	605	1,009
Taxes other than on income	-	309	191	500
Other	-	(2)	(1)	(3)
Diversified business				
Cost of sales	-	854	44	898
Depreciation and amortization	-	13	10	23
Impairment of assets	-	44	47	91
Other	-	36	16	52
Total operating expenses	14	4,943	3,304	8,261
Operating (loss) income	(14)	533	790	1,309
Other (expense) income, net	(33)	55	21	43
Interest charges, net	276	184	165	625
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	404	646	727
Income tax (benefit) expense	(123)	90	237	204
Equity in earnings of consolidated subsidiaries	779	-	(779)	-
Minority interest in subsidiaries' income, net of tax	-	(9)	-	(9)
Income (loss) from continuing operations	579	305	(370)	514
Discontinued operations, net of tax	(8)	392	(327)	57
Net income (loss)	$ 571	$ 697	$ (697)	$ 571

Condensed Consolidating Statement of Income
Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ -	$ 3,955	$ 3,990	$ 7,945
Diversified business	-	1,244	(21)	1,223
Total operating revenues	-	5,199	3,969	9,168
Operating expenses				
Utility				
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	-	334	588	922
Taxes other than on income	4	279	177	460
Other	-	(26)	(11)	(37)
Diversified business				
Cost of sales	-	1,267	86	1,353
Depreciation and amortization	-	21	20	41
Other	-	19	13	32
Total operating expenses	16	4,763	3,169	7,948
Operating (loss) income	(16)	436	800	1,220
Other income (expense), net	66	(5)	(52)	9
Interest charges, net	300	166	108	574
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(250)	265	640	655
Income tax (benefit) expense	(63)	(70)	96	(37)
Equity in earnings of consolidated subsidiaries	884	-	(884)	-
Minority interest in subsidiaries' loss, net of tax	-	29	-	29
Income (loss) from continuing operations	697	364	(340)	721
Discontinued operations, net of tax	-	10	(35)	(25)
Cumulative effect of change in accounting principle, net of tax	-	-	1	1
Net income (loss)	$ 697	$ 374	$ (374)	$ 697

Condensed Consolidating Statement of Income
Year ended December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ -	$ 3,525	$ 3,628	$ 7,153
Diversified business	-	895	5	900
Total operating revenues	-	4,420	3,633	8,053
Operating expenses				
Utility				
Fuel used in electric generation	-	1,175	836	2,011
Purchased power	-	567	301	868
Operation and maintenance	10	630	835	1,475
Depreciation and amortization	-	281	597	878
Taxes other than on income	(2)	254	173	425
Other	-	(2)	(11)	(13)
Diversified business				
Cost of sales	-	911	81	992
Depreciation and amortization	-	21	20	41
Other	-	46	58	104
Total operating expenses	8	3,883	2,890	6,781
Operating (loss) income	(8)	537	743	1,272
Other income (expense), net	65	(4)	(46)	15
Interest charges, net	295	152	119	566
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(238)	381	578	721
Income tax (benefit) expense	(57)	12	112	67
Equity in earnings of consolidated subsidiaries	940	-	(940)	-
Minority interest in subsidiaries' loss, net of tax	-	19	-	19
Income (loss) from continuing operations	759	388	(474)	673
Discontinued operations, net of tax	-	86	-	86
Net income (loss)	$ 759	$ 474	$ (474)	$ 759

Condensed Consolidating Balance Sheet
December 31, 2006

(in millions)		Subsidiary		Progress Energy,
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 of discontinued operations	-	45	842	887
Other current assets	27	1,109	1,030	2,166
Total current assets	259	1,231	2,095	3,585
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	1,583	1,507	3,216
Total deferred debits and other assets	10,866	1,584	(5,579)	6,871
Total assets	$ 11,125	$ 9,152	$ 5,424	$ 25,701
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 of discontinued operations	-	13	176	189
Other current liabilities	210	1,281	814	2,305
Total current liabilities	210	1,495	1,113	2,818
Deferred credits and other liabilities				
Noncurrent income tax liabilities	-	61	245	306
Regulatory liabilities	-	1,091	1,452	2,543
Accrued pension and other benefits	14	377	566	957
Other liabilities and deferred credits	33	559	1,261	1,853
Total deferred credits and other liabilities	47	2,088	3,524	5,659
Total capitalization and liabilities	$ 11,125	$ 9,152	$ 5,424	$ 25,701

Condensed Consolidating Balance Sheet
December 31, 2005

(in millions)		Subsidiary		Progress Energy,
Utility plant, net	$ -	$ 5,821	$ 8,621	$ 14,442
Current assets				
Cash and cash equivalents	239	239	127	605
Short-term investments	-	-	191	191
Notes receivable from affiliated companies	467	-	(467)	-
Deferred fuel cost	-	341	261	602
Assets of discontinued operations	-	757	1,809	2,566
Other current assets	22	992	1,029	2,043
Total current assets	728	2,329	2,950	6,007
Deferred debits and other assets				
Investment in consolidated subsidiaries	11,594	-	(11,594)	-
Goodwill	-	2	3,653	3,655
Other assets and deferred debits	259	1,561	1,138	2,958
Total deferred debits and other assets	11,853	1,563	(6,803)	6,613
Total assets	$ 12,581	$ 9,713	$ 4,768	$ 27,062
Capitalization				
Common stock equity	$ 8,038	$ 3,039	$ (3,039)	$ 8,038
Preferred stock of subsidiaries - not subject to mandatory redemption	-	34	59	93
Minority interest	-	31	5	36
Long-term debt, affiliate	-	440	(170)	270
Long-term debt, net	3,873	2,636	3,667	10,176
Total capitalization	11,911	6,180	522	18,613
Current liabilities				
Current portion of long-term debt	404	109	-	513
Notes payable to affiliated companies	-	315	(315)	-
Short-term debt	-	102	73	175
Liabilities of discontinued operations	-	226	316	542
Other current liabilities	245	762	812	1,819
Total current liabilities	649	1,514	886	3,049
Deferred credits and other liabilities				
Noncurrent income tax liabilities	-	-	198	198
Regulatory liabilities	-	1,189	1,338	2,527
Accrued pension and other benefits	12	307	546	865
Other liabilities and deferred credits	9	523	1,278	1,810
Total deferred credits and other liabilities	21	2,019	3,360	5,400
Total capitalization and liabilities	$ 12,581	$ 9,713	$ 4,768	$ 27,062

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	$ 1,015	$ (398)	$ 1,912
Investing activities				
Gross utility property additions	-	(718)	(705)	(1,423)
Diversified business property additions	-	(2)	-	(2)
Nuclear fuel additions	-	(12)	(102)	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	-	1,239	415	1,654
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	561	(1,033)	271
Financing activities				
Issuance of common stock	185	-	-	185
Proceeds from issuance of long-term debt, net	397	-	-	397
Net decrease in short-term debt	-	(102)	(73)	(175)
Retirement of long-term debt	(2,091)	(109)	-	(2,200)
Retirement of long-term affiliate debt	-	(131)	131	-
Dividends paid on common stock	(607)	-	-	(607)
Dividends paid to parent	-	(1,135)	1,135	-
Changes in advances from affiliates	-	(243)	243	-
Cash distributions to minority interests of consolidated subsidiary	-	(79)	-	(79)
Other financing activities	(8)	71	(52)	11
Net cash (used) provided by financing activities	(2,124)	(1,728)	1,384	(2,468)
Cash provided (used) by discontinued operations				
Operating activities	-	92	(6)	86
Investing activities	-	(139)	(2)	(141)
Financing activities	-	-	-	-
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	$ 409	$ 509	$ 1,175
Investing activities				
Gross utility property additions	-	(496)	(584)	(1,080)
Diversified business property additions	-	(6)	-	(6)
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)	1	(37)
Net cash provided (used) by investing activities	690	(108)	(1,496)	(914)
Financing activities				
Issuance of common stock	208	-	-	208
Proceeds from issuance of long-term debt, net	-	744	898	1,642
Net increase in short-term debt	(170)	(191)	(148)	(509)
Retirement of long-term debt	(160)	(104)	(300)	(564)
Retirement of long-term affiliate debt	-	(369)	369	-
Dividends paid on common stock	(582)	-	-	(582)
Dividends paid to parent	-	(2)	2	-
Changes in advances from affiliates	-	(101)	101	-
Other financing activities	(9)	53	(10)	34
Net cash (used) provided by financing activities	(713)	30	912	229
Cash provided (used) by discontinued operations				
Operating activities	-	93	201	294
Investing activities	-	(206)	(26)	(232)
Financing activities	-	(2)	-	(2)
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

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2004

(in millions)	Parent	Subsidiary	Other	Progress Energy,
Net cash provided by operating activities	$ 653	$ 469	$ 287	$ 1,409
Investing activities				
Gross utility property additions	-	(482)	(516)	(998)
Diversified business property additions	-	(6)	-	(6)
Nuclear fuel additions	-	-	(101)	(101)
Proceeds from sales of discontinued operations and other assets, net of cash divested	-	343	29	372
Purchases of available-for-sale securities and other investments	-	(569)	(2,565)	(3,134)
Proceeds from sales of available-for-sale securities and other investments	-	569	2,679	3,248
Changes in advances to affiliates	27	(5)	(22)	-
Contributions to consolidated subsidiaries	(15)	-	15	-
Other investing activities	-	(23)	(7)	(30)
Net cash provided (used) by investing activities	12	(173)	(488)	(649)
Financing activities				
Issuance of common stock	73	-	-	73
Proceeds from issuance of long-term debt, net	365	56	-	421
Net increase in short-term debt	170	293	217	680
Retirement of long-term debt	(705)	(68)	(339)	(1,112)
Dividends paid on common stock	(558)	-	-	(558)
Dividends paid to parent	-	(340)	340	-
Changes in advances from affiliates	-	(205)	205	-
Contributions from parent	-	12	(12)	-
Other financing activities	(5)	15	1	11
Net cash (used) provided by financing activities	(660)	(237)	412	(485)
Cash provided (used) by discontinued operations				
Operating activities	-	145	46	191
Investing activities	-	(190)	(9)	(199)
Financing activities	-	(5)	(241)	(246)
Net increase in cash and cash equivalents	5	9	7	21
Cash and cash equivalents at beginning of year	-	14	20	34
Cash and cash equivalents at end of year	$ 5	$ 23	$ 27	$ 55

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][b]	Second [a][b]	Third [a][b]	Fourth [a][b]
2006				
Operating revenues	**$ 2,223**	**$ 2,298**	**$ 2,776**	**$ 2,273**
Operating income	**268**	**210**	**557**	**274**
Income from continuing operations	**85**	**19**	**283**	**127**
Net income (loss)	**45**	**(47)**	**319**	**254**
Common stock data				
Basic earnings per common share				
Income from continuing operations	**0.34**	**0.08**	**1.13**	**0.51**
Net income (loss)	**0.18**	**(0.19)**	**1.27**	**1.01**
Diluted earnings per common share				
Income from continuing operations	**0.34**	**0.08**	**1.12**	**0.51**
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**
2005				
Operating revenues	$ 2,051	$ 2,079	$ 2,743	$ 2,295
Operating income	237	119	539	325
Income from continuing operations before cumulative effect of change in accounting principle	103	2	457	159
Net income (loss)	93	(1)	450	155
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.42	0.01	1.84	0.64
Net income (loss)	0.38	(0.01)	1.82	0.62
Diluted earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.42	0.01	1.84	0.64
Net income (loss)	0.38	(0.01)	1.81	0.62
Dividends declared per common share	0.590	0.590	0.590	0.605
Market price per share -High	45.33	45.83	46.00	45.50
- Low	40.63	40.61	41.90	40.19

[a] Operating results have been restated for discontinued operations.

[b] Certain amounts have been reclassified to conform to current period presentation.

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 first quarter of 2005 included $31 million recorded for estimated severance expense for workforce restructuring and implementation of an automated meter reading initiative at PEF; the second and fourth quarters of 2005 included reversals of estimated severance expense of $13 million each quarter. The second quarter of 2005 included a $141 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 16A). The second quarter of 2006 includes a $91 million impairment charge to our synthetic fuels assets and a portion of our coal terminal assets (See Notes 8 and 9). The 2006 and 2005 amounts were restated for discontinued operations (See Note 3).

PEC

Summarized quarterly financial data was as follows:

(in millions)	First (a)	Second (a)	Third (a)	Fourth (a)
2006				
Operating revenues	**$ 978**	**$ 936**	**$ 1,200**	**$ 972**
Operating income	**189**	**174**	**346**	**178**
Net income	**86**	**76**	**189**	**106**
2005				
Operating revenues	$ 935	$ 861	$ 1,185	$ 1,010
Operating income	221	140	343	227
Net income	116	67	184	126

(a) Certain amounts have been reclassified to conform to current period presentation.

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 first quarter of 2005 included $14 million recorded for estimated severance expense for workforce restructuring; the second and fourth quarters of 2005 included reversals of estimated severance expense of $6 million and $5 million, respectively. The second quarter of 2005 included a $29 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 16A).

PEF

Summarized quarterly financial data was as follows:

(in millions)	First (a)	Second (a)	Third (a)	Fourth (a)
2006				
Operating revenues	**$ 1,007**	**$ 1,147**	**$ 1,399**	**$ 1,086**
Operating income	**117**	**167**	**237**	**122**
Net income	**53**	**87**	**125**	**63**
2005				
Operating revenues	$ 848	$ 908	$ 1,227	$ 972
Operating income	89	51	247	112
Net income	44	10	151	55

(a) Certain amounts have been reclassified to conform to current period presentation.

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 first quarter of 2005 included $14 million recorded for estimated severance expense for workforce restructuring and implementation of an automated meter reading initiative; the second and fourth quarters of 2005 included reversals of estimated severance expense of $5 million and $6 million, respectively. The second quarter of 2005 included a $90 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 16A).

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				

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [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	(69,995)		(69,995)	[redacted]	[redacted]
2	15,250		15,250	[redacted]	[redacted]
3	(56,824)		(56,824)	[redacted]	[redacted]
4	(41,574)		(41,574)	259,708,903	259,667,329
5	(111,569)		(111,569)	[redacted]	[redacted]
6	(111,569)		(111,569)	[redacted]	[redacted]
7	19,986		19,986	[redacted]	[redacted]
8	(1,443,435)		(1,443,435)	[redacted]	[redacted]
9	(1,423,449)		(1,423,449)	328,236,391	326,812,942
10	(1,535,018)		(1,535,018)	[redacted]	[redacted]

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	12/31/2006	End of 2006/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)	9,153,567,677	9,151,036,437
4	Property Under Capital Leases	54,195,256	54,195,256
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	9,207,762,933	9,205,231,693
9	Leased to Others		
10	Held for Future Use	7,422,006	7,422,006
11	Construction Work in Progress	641,485,881	641,485,881
12	Acquisition Adjustments	17,717,964	17,717,964
13	Total Utility Plant (8 thru 12)	9,874,388,784	9,871,857,544
14	Accum Prov for Depr, Amort, & Depl	4,401,159,420	4,400,024,109
15	Net Utility Plant (13 less 14)	5,473,229,364	5,471,833,435
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,287,022,870	4,287,022,870
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	116,819,559	115,684,248
22	Total In Service (18 thru 21)	4,403,842,429	4,402,707,118
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	-2,683,008	-2,683,008
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,401,159,421	4,400,024,110

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	12/31/2006	End of 2006/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
	1,135,311				14
	1,395,929				15
					16
					17
					18
					19
					20
	1,135,311				21
	1,135,311				22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
	1,135,311				33

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

Column B, line 6 - In Q2 of 2006, we started including 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" are included with "Classified Plant in Service" in the same general ledger account, combining the two was deemed to be the more 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	12/31/2006	End of 2006/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	851,954	11,629,959
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	851,954	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	6,110,241	6,807,445
9	In Reactor (120.3)	98,974,953	122,773
10	SUBTOTAL (Total 8 & 9)	105,085,194	
11	Spent Nuclear Fuel (120.4)	49,800,071	
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	80,246,740	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	75,490,479	
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	12/31/2006	End of 2006/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
		12,481,913	3
			4
			5
		12,481,913	6
			7
	12,307,249	610,437	8
		99,097,726	9
		99,708,163	10
	49,800,071		11
			12
-23,334,045	49,800,071	53,780,714	13
		58,409,362	14
			15
			16
			17
			18
			19
			20
			21
			22

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

$12,307,249 transferred to 120.1.

Schedule Page: 202 Line No.: 11 Column: e

$49,800,071 transferred to 120.5.

Schedule Page: 202 Line No.: 13 Column: e

$49,800,071 transferred from 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	12/31/2006	End of 2006/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	6,401,753	2,048,276
4	(303) Miscellaneous Intangible Plant	117,195,695	5,010,101
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	123,597,448	7,058,377
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	6,450,314	
9	(311) Structures and Improvements	285,608,312	656,750
10	(312) Boiler Plant Equipment	833,592,824	52,609,186
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	446,975,960	7,067,377
13	(315) Accessory Electric Equipment	158,426,127	1,308,311
14	(316) Misc. Power Plant Equipment	29,844,802	1,216,638
15	(317) Asset Retirement Costs for Steam Production	8,881,846	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,769,780,185	62,858,262
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	-150,918	
19	(321) Structures and Improvements	220,626,715	1,826,083
20	(322) Reactor Plant Equipment	264,248,689	3,053,922
21	(323) Turbogenerator Units	91,786,585	1,064,504
22	(324) Accessory Electric Equipment	176,737,667	4,011,361
23	(325) Misc. Power Plant Equipment	40,074,542	1,532,745
24	(326) Asset Retirement Costs for Nuclear Production	50,846	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	793,374,126	11,488,615
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	18,888,990	-169,031
38	(341) Structures and Improvements	115,459,678	225,983
39	(342) Fuel Holders, Products, and Accessories	78,739,589	248,502
40	(343) Prime Movers	796,580,340	3,364,491
41	(344) Generators	311,280,012	643,774
42	(345) Accessory Electric Equipment	137,908,414	542,730
43	(346) Misc. Power Plant Equipment	18,317,008	-133,606
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,477,174,031	4,722,843
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,040,328,342	79,069,720

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
			122,205,796		4
			130,655,825		5
					6
					7
			6,450,314		8
118,973			286,146,089		9
7,735,967	197		878,466,240		10
					11
2,025,404			452,017,933		12
125,979	221,430		159,829,889		13
38,467	22,000		31,044,973		14
			8,881,846		15
10,044,790	243,627		1,822,837,284		16
					17
			-150,918		18
774,472	171,538		221,849,864		19
6,315,402			260,987,209		20
394,285			92,456,804		21
1,233,813	-221,430		179,293,785		22
290,730	-76,836		41,239,721		23
			50,846		24
9,008,702	-126,728		795,727,311		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
-16,488			18,736,447		37
			115,685,661		38
149,516			78,838,575		39
21,337,865			778,606,966		40
			311,923,786		41
2,733			138,448,411		42
			18,183,402		43
					44
21,473,626			1,460,423,248		45
40,527,118	116,899		4,078,987,843		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	12/31/2006	End of 2006/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	64,606,799	1,253,892
49	(352) Structures and Improvements	20,661,266	1,991,937
50	(353) Station Equipment	435,186,035	36,210,199
51	(354) Towers and Fixtures	66,464,850	901
52	(355) Poles and Fixtures	264,013,368	63,594,948
53	(356) Overhead Conductors and Devices	213,972,008	21,216,957
54	(357) Underground Conduit	7,010,980	
55	(358) Underground Conductors and Devices	9,496,402	102,185
56	(359) Roads and Trails	1,923,606	1,210,296
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,083,335,314	125,581,315
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	21,802,476	1,100,181
61	(361) Structures and Improvements	22,287,896	1,630,767
62	(362) Station Equipment	356,918,496	27,845,525
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	439,090,561	27,222,565
65	(365) Overhead Conductors and Devices	482,604,645	34,688,408
66	(366) Underground Conduit	172,411,513	21,113,141
67	(367) Underground Conductors and Devices	441,851,516	28,060,461
68	(368) Line Transformers	410,885,432	43,789,139
69	(369) Services	433,817,959	34,678,439
70	(370) Meters	133,985,854	61,536,217
71	(371) Installations on Customer Premises	2,222,150	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	267,101,837	18,269,113
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,184,980,335	299,933,956
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	10,689,234	
87	(390) Structures and Improvements	94,424,830	20,478,771
88	(391) Office Furniture and Equipment	10,473,110	1,042,638
89	(392) Transportation Equipment	127,972,606	17,545,300
90	(393) Stores Equipment	3,352,025	718,297
91	(394) Tools, Shop and Garage Equipment	11,157,750	2,504,028
92	(395) Laboratory Equipment	3,188,319	193,590
93	(396) Power Operated Equipment	3,349,676	657,713
94	(397) Communication Equipment	57,738,759	2,119,344
95	(398) Miscellaneous Equipment	3,684,243	2,745,622
96	SUBTOTAL (Enter Total of lines 86 thru 95)	326,030,552	48,005,303
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)	328,004,791	48,005,303
100	TOTAL (Accounts 101 and 106)	8,760,246,230	559,648,671
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)	8,760,246,230	559,648,671

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
-11,432	-13,104		65,859,019		48
1,090,371	-36,404		21,526,428		49
1,989,521	-908,832		468,497,881		50
			66,465,751		51
699,157	-821,843		326,087,316		52
378,521	-73,835		234,736,609		53
			7,010,980		54
			9,598,587		55
			3,133,902		56
					57
4,146,138	-1,854,018		1,202,916,473		58
					59
43,029	-2,264		22,857,364		60
45,528	-23,515		23,849,620		61
911,975	-301,811		383,550,235		62
					63
1,080,417	-756,965		464,475,744		64
4,485,679	1,228,160		514,035,534		65
213,486	-52,035		193,259,133		66
2,865,090	-392,684		466,654,203		67
3,920,993	32,158		450,785,736		68
10,821,029	-784,978		456,890,391		69
82,445,029	-7,425		113,069,617		70
			2,222,150		71
					72
2,672,733	-7,461,446		275,236,771		73
					74
109,504,988	-8,522,805		3,366,886,498		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
-17,098	-2,026		10,704,306		86
831,000	62,328		114,134,929		87
1,150,091			10,365,657		88
1,281,941			144,235,965		89
63,809			4,006,513		90
51,535			13,610,243		91
267,524			3,114,385		92
			4,007,389		93
438,865	-2,946		59,416,292		94
409,985			6,019,880		95
4,477,652	57,356		369,615,559		96
					97
			1,974,239		98
4,477,652	57,356		371,589,798		99
158,655,896	-10,202,568		9,151,036,437		100
					101
					102
					103
158,655,896	-10,202,568		9,151,036,437		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	12/31/2006	End of 2006/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	05/05	1,046,210
3	PERRY - FLORIDA STATE LINE	12/92	05/05	1,808,764
4	HIGH SPRINGS - JASPER - FLORIDA STATE LINE	03/96	05/05	2,584,486
5	BELCHER ROAD SUBSTATION	05/96	05/05	267,012
6				
7	OTHER LAND RIGHTS	07/90	05/05	962,674
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	PERRY - CROSS CITY - DUNNELLON	7/90	5/05	752,861
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			7,422,007

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/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	HINES PB4-MASTER	222,407,460
2	60BT0CRP0 BARTOW REPOWERING	105,714,265
3	STEAM GENERATOR REPLACEMENT	57,726,450
4	60KK8-1830T1 HINES PB4 H-WLW	32,056,959
5	60CRN5CRP0 CR #5 FGD	11,321,159
6	60ANC9CRP0 COOLING TOWER REPL	8,525,086
7	60CRNCRP0 CR UNIT 4 SCR	6,382,529
8	60CR11CRPM BARGE UNLOADER	5,354,722
9	60KK8-1650T1 NEW RIVER (WREC)	5,344,387
10	CP HEC PB1B COMPRESSOR OUTAGE	5,084,561
11	60CRN4CRP0 CR UNIT #4 FGD	5,072,700
12	60GB9D GSU XFMR REPL	4,820,576
13	60CRN5CRPO CR #5 SCR	3,868,958
14	60X00D PEP FURN &AV EQ.	3,439,407
15	60440D JAMESTOWN OC - RENOV	3,094,201
16	60440D WALSINGHAM OC-UPGRADE	3,001,416
17	60GB9D RB SUMP MASTER	2,881,503
18	60480 NNP COLA DEVLOP PEF	4,396,227
19	60KK8-1682S1 ATWATER NEW SUB	2,575,416
20	60KK8-1830S3 HINES PB4-NEW SUB	2,277,929
21	60GB9D CR3 POWER UPRATE	2,110,654
22	60GB9D CR3 LICENSE RENEWAL MAS	2,106,133
23	60CR9CRPM CHUTE REDESIGN	2,104,709
24	60898 BELLEAIR CAUSEWAY	2,054,195
25	600341556D1 PINE RIDGE SUB	1,835,472
26	60KK8-1721S1 BRONSON NEW SUB	1,814,560
27	608981025D1 POINCIANA	1,639,584
28	CP IC TANK 1 & 2 PIPE DBL BOTT	1,592,739
29	60034 2006 ACCLELERATED LG	1,374,033
30	60KK8-1694T1 WESTWOOD ACRES	1,327,294
31	60GB9D CW AMERTAP RPL-BEAUDREY	1,312,825
32	600340403S7-PEACOCK LRC	1,302,238
33	60KK8-1235S7 AVALON CHANGE	1,218,023
34	60547-143T3 CF POLE REPL (GR)	1,179,002
35	600341816D1-BARNUM CTY	1,171,944
36	CP HEC PB1A 2005 FALL CI PARTS	1,156,958
37	600341854D2 OCC#1 UPGRADE	1,089,076
38	60KK8-1864S1 GINNIE NEW SUB	1,085,245
39	600341918S1-CF INDUSTRIES SUB	1,034,476
40	60BT2CRP4 BT2 S/U TRANSFORMER	1,021,431
41		
42	Other Minor Projects	116,609,379
43	TOTAL	641,485,881

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

Increase over last year attributed to increase in the Hines Powerblock 4 and Bartow Re-powering projects.

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	12/31/2006	End of 2006/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	4,169,372,967	4,169,372,967		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	266,506,666	266,506,666		
4	(403.1) Depreciation Expense for Asset Retirement Costs	354,560	354,560		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts	7,112,679	7,112,679		
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock - Oil and Rail Cars	2,474,188	2,474,188		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	276,448,093	276,448,093		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	158,655,896	158,655,896		
13	Cost of Removal	40,746,589	40,746,589		
14	Salvage (Credit)	455,832	455,832		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	198,946,653	198,946,653		
16	Other Debit or Cr. Items (Describe, details in footnote):	40,148,463	40,148,463		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,287,022,870	4,287,022,870		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,420,902,979	1,420,902,979		
21	Nuclear Production	573,478,074	573,478,074		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	493,530,955	493,530,955		
25	Transmission	467,447,245	467,447,245		
26	Distribution	1,237,741,938	1,237,741,938		
27	Regional Transmission and Market Operation				
28	General	93,921,679	93,921,679		
29	TOTAL (Enter Total of lines 20 thru 27)	4,287,022,870	4,287,022,870		

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

Provision for Steam 312.0 Rail Cars -	$1,644,515
Provision for Steam 311.0-315.0 & 316.3 Bartow-Anclote Pipeline -	829,673
	$2,474,188

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

Adjustments to Reserve:

Rail Cars	27,620,025
Withlacoochee River Elec Coop	12,569,319
Adjustments & Transfers	(40,881)
	40,148,463

Schedule Page: 219 Line No.: 28 Column: c

Decrease in number is due to "Unspecified" items. In the past they were included with General Plant instead of being allocated to the appropriate function. The majority of the dollars were added to Steam and Other Production.

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	12/31/2006	End of 2006/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	135,760,761	239,606,898	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)	129,576,400	161,500,391	Various
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	21,244,388	20,750,479	Power Supply
8	Transmission Plant (Estimated)	1,417,609	1,071,828	Transmission
9	Distribution Plant (Estimated)	4,256,302	4,781,775	Customer Service
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	510,511	454,069	Various
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	157,005,210	188,558,542	
13	Merchandise (Account 155)	259,681	550,736	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)	9,156,997	5,825,542	Various
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	302,182,649	434,541,718	

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

Account 154 Plant Materials and Operating Supplies includes an Inventory Reserve account credit balance of $3,207,194. During 2005, $1,519,306 was charged against the reserve. Current reserve levels were sufficient based on current reviews of inventory.

Account 154 Plant Materials and Operating Supplies is a net balance including the co-owned inventory balance of $4,564,661. Co-owned inventory accounts include Crystal River Unit 3 valued at $2,755,228 and Intercession City, Siemens unit 11 valued at $1,809,433 at the end of 2005.

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

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.: 16 Column: b

Account 163 - Stores Expense Undistributed was charged with $2,262,056 and credited with $1,885,407 for a net charge of $376,649 during 2005. These charges to operations, maintenance and capital accounts were to record various inventory adjustments for 2005.

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

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.

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	12/31/2006	End of 2006/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2007 No. (d)	2007 Amt. (e)
1	Balance-Beginning of Year	168,432.00	9,611,854	125,653.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	134,295.00	7,670,903		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	34,137.00	1,940,951	125,653.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	3,343.00		3,343.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year	3,343.00		3,343.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		1,521,757		
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2008		2009		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
125,653.00	1,750	125,653.00		2,503,872.00		3,049,263.00	9,613,604	1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						134,295.00	7,670,903	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
125,653.00	1,750	125,653.00		2,503,872.00		2,914,968.00	1,942,701	29
								30
								31
								32
								33
								34
								35
3,343.00		3,343.00		67,600.00		80,972.00		36
								37
								38
								39
3,343.00		3,343.00		67,600.00		80,972.00		40
								41
								42
								43
					473,540		1,995,297	44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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	436,359	16,092,702
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	116,379,856	73,892,516
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL	257,722,326			116,816,215	89,985,218

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	12/31/2006	End of 2006/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	TECO Transmission Study	2,499	1861900		
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Vandolah Generation Study	15,501	1861900	2,300	1861900
23	NFPP Generation Study	23,408	1861900		
24	FL Biomass Generation Study	577	1861900		
25	Calpine Generation Study			2,194	1861900
26					
27					
28					
29					
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32					
33					
34					
35					
36					
37					
38					
39					
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	12/31/2006	End of 2006/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 (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Accmulated Deferred Taxes - FAS 109	108,874,000	2,226,000	4101000	801,000	110,299,000
2	Period of Amortization occurs					
3	as temporary differences occur.					
4						
5	Nuclear Decom/Decontamination	1,993,359	320,581	5188200	2,253,347	60,593
6	Amortization Period = 12 months					
7						
8	Load Control Switches - Investment	3,126,416	1,693,711	1861902	1,129,591	3,690,536
9	Load Control Switches - Amortization	(1,511,940)	794,213	9080120	711,700	-1,429,427
10						
11	Deferred Energy Conservation Expense	(9,598,258)	3,225,222	9080110	5,188,062	-11,561,098
12						
13	Sebring Transition Rider	8,757,914	18,707	1861904	3,299,998	5,476,623
14	Sebring - Over(Under) Recovered	(1,189,737)	3,776,904	4044002	4,126,820	-1,539,653
15						
16	Interest on Tax Deficiency	419,109	1,040,029	4310024	3,232,834	-1,773,696
17						
18	Deferred GPIF Asset	532,353		4560096	532,353	
19	Deferred Fuel Expense - Full Req	12,488,757	2,493,732	5572002	11,221,285	3,761,204
20	Deferred Fuel Expense - 01/04 - 12/04	79,157,270		5572002	79,157,270	
21	Deferred Fuel Expense - 01/05 - 12/05	236,919,841		5572002	236,534,786	385,055
22	Deferred Capacity Expense - 01/05 - 12/05	12,197,739		5572001	11,616,464	581,275
23	Deferred Capacity Expense - 01/06 - 12/06		26,634,529	5572001	18,453,267	8,181,262
24						
25	Deferred Environmental Cost Recovery	6,197,591	10,057,502	9350003	1,693,991	14,561,102
26	Accrued Environmental cost Recovery	19,309,000	43,405,552	2284800	20,201,971	42,512,581
27						
28	RTO Set Up Costs	4,510,108	3,052	5660000	4,513,160	
29						
30	Florida Minimum Pension Liability	7,221,715	130,182,525	2283151-70	7,239,121	130,165,119
31						
32	Regulatory Asset Derivative MTM Oil	6,104,892	299,658,527	2543015-7	227,693,432	78,069,987
33						
34	Regulatory Asset - FAS 143 Asbestos	187,999	27,033	4074002	2,029	213,003
35						
36	Rate Case Expense		1,846,399	4073702	923,199	923,200
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	495,698,128	527,404,218		640,525,680	382,576,666

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	12/31/2006	End of 2006/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	6,587	24,925,336	Various	24,975,667	-43,744
2	Southern Company Capacity	803,433				803,433
3	FL Rate Case	1,844,213	2,186	Various	1,846,399	
4	Homosassa Fuel Cell	213,518	35,120	Various	232,718	15,920
5	Longwood Hydrogen Vehicle	118,204	131,006	Various	198,538	50,672
6	Hurricane Dennis	2,520,464	7,232,126	Various	9,743,710	8,880
7	Hurricane Katrina	1,265,204	11,378	Various	1,276,582	
8	Hurricane Katrina Off System	987,629	1,117	Various	988,746	
9	Katrina Cleco Assist	635,262	459,604	Various	1,094,866	
10	Katrina Entergy Assist	1,488,658	1,934,328	Various	3,422,986	
11	Rita Entergy Assist	3,345,190	679,498	Various	4,023,021	1,667
12	Hurricane Wilma	3,965,452	4,924,752	Various	8,890,204	
13	Wilma FP&L Assist	1,684,943	185,221	Various	1,870,164	
14	Hurricane Alberto		5,686,708	Various	4,642,767	1,043,941
15	Hurricane Ernesto		4,962,583	Various	3,922,803	1,039,780
16	Vacation Pay Accrual	4,163,303	13,304,211	242	12,484,782	4,982,732
17	Labor Accrual	1,168,180	30,641,352	242	30,303,094	1,506,438
18	Minimum Pension Liability	1,246,237			1,246,237	
19	Oil Swap	5,000,000	59,500,000		64,500,000	
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	30,456,477				9,409,719

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	12/31/2006	End of 2006/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	UNBILLED REVENUE	30,121,000	35,630,000
3	LIFE/MEDICAL BENEFITS	70,276,000	97,365,000
4	UNAMORTIZED INVESTMENT TAX CREDIT	11,532,000	9,060,000
5	REGULATORY LIABILITY	19,362,000	17,845,000
6	NUCLEAR DECOMMISSIONING	44,077,000	99,579,000
7	OTHER	25,689,047	120,767,000
8	TOTAL Electric (Enter Total of lines 2 thru 7)	201,057,047	380,246,000
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)	201,057,047	380,246,000

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	12/31/2006	End of 2006/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		
12				
13				
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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	12/31/2006	End of 2006/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
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
						12
						13
						14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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	650,890
25	Misc PIC - Stock Options	655,780
26	Misc PIC - Performance Share Sub Plan (PSSP)	3,258,426
27		
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40	TOTAL	745,926,367

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	12/31/2006	End of 2006/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	First Mortgage Bonds - 6.65%	300,000,000	3,182,657
2			429,000 D
3	First Mortgage Bonds - 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	1,491,598
12			2,115,000 D
13	Medium Term Note (Sebring) - 6.67%	30,700,000	280,604
14			
15	Medium Term Note - 6.77%	45,000,000	271,939
16			
17	Medium Term Note - 6.81%	85,000,000	534,680
18			
19	Medium Term Note - 6.75%	150,000,000	5,528,498
20			436,500 D
21	Series A Senior Note - Floating Rate	450,000,000	349,410
22			1,575,000 D
23	Pollution Control Bonds (Citrus) 2002A	108,550,000	2,356,705
24			
25	Pollution Control Bonds (Citrus) 2002B	100,115,000	2,081,983
26			
27	Pollution Control Bonds (Citrus) 2002C	32,200,000	756,175
28			
29	RCA - 5 Year		990,975
30			
31			
32			
33	TOTAL	2,631,565,000	37,966,015

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/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)	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	5,499,994	3
						4
2/21/03	3/01/13	2/21/03	3/01/13	425,000,000	20,400,000	5
						6
2/21/03	3/01/33	2/21/03	3/01/33	225,000,000	13,275,000	7
						8
11/21/03	12/01/15	11/21/03	12/01/15	300,000,000	15,300,000	9
						10
5/16/05	6/01/10	5/16/05	6/01/10	300,000,000	13,500,000	11
						12
4/20/93	4/01/08	4/20/93	4/01/08	5,500,006	476,906	13
						14
7/25/97	7/01/06	7/25/97	7/01/06		1,523,250	15
						16
7/25/97	7/01/07	7/25/97	7/01/07	85,000,000	5,788,500	17
						18
2/13/98	2/01/28	2/13/98	2/01/28	150,000,000	10,125,000	19
						20
12/13/05	11/14/08	12/13/05	11/14/08	450,000,000	24,937,202	21
						22
8/13/02	1/01/27	8/13/02	1/01/27	108,550,000	3,745,141	23
						24
8/20/02	1/01/22	8/20/02	1/01/22	100,115,000	3,344,770	25
						26
7/24/02	1/01/18	7/24/02	1/01/18	32,200,000	1,064,752	27
						28
3/28/05	3/28/10	3/28/05	3/28/10			29
						30
						31
						32
				2,561,365,006	138,930,515	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	12/31/2006	End of 2006/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	328,236,391
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	164,086,617
11		
12	Deductions Recorded on Books Not Deducted for Return	964,489,844
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	-888,716,491
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	568,096,361
28	Show Computation of Tax:	
29	Provision for Federal Income Tax at 35%	198,833,726
30	True up Entries and Other Tax Benefits	7,950,885
31	Total Federal Income Tax Provision (409120F-409220F) True up Entries	206,784,611
32		
33		
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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	12/31/2006	End of 2006/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	3,725,647		206,784,611	264,564,988	
3	FICA	597,886		21,147,398	21,085,050	
4	Unemployment	22,665		269,451	286,991	
5	Special Fuel Tax					
6	Excise Tax					
7	Highway Use			36,276	36,276	
8	Payroll Tax	1,732,443			244,615	
9	SUBTOTAL	6,078,641		228,237,736	286,217,920	
10						
11	STATE TAXES					
12	Income	2,814,057		34,465,397	30,670,286	
13	Income Tax Subsidiary					
14	Gross Receipts	12,727,927		102,802,657	100,431,639	
15	Unemployment	152,987		1,818,337	1,936,960	
16	Intangibles					
17	Regulatory Assessment	1,425,609		3,007,683	2,839,470	
18	Sales Tax-Company Use	11,999		149,549	148,721	
19	SUBTOTAL	17,132,579		142,243,623	136,027,076	
20						
21	COUNTY & LOCAL TAXES					
22	Property-County & Local	3,343,064		88,308,257	91,651,321	
23	FL Privilege License			7,337	7,337	
24	Franchise-Local	6,441,257		96,028,290	95,449,616	
25						
26						
27	Adj-Use Tax on Purchases					
28	SUBTOTAL	9,784,321		184,343,884	187,108,274	
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	32,995,541		554,825,243	609,353,270	

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	12/31/2006	End of 2006/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-54,054,730		203,726,041			3,058,570	2
660,233		18,893,455			2,253,942	3
5,125					269,451	4
						5
						6
		36,276				7
1,487,828						8
-51,901,544		222,655,772			5,581,963	9
						10
						11
6,609,169		33,701,977			763,420	12
						13
15,098,945		102,802,657				14
34,363					1,818,337	15
						16
1,593,822		3,007,683				17
12,827		149,549				18
23,349,126		139,661,866			2,581,757	19
						20
						21
		88,149,084			159,173	22
		7,337				23
7,019,931		96,028,290				24
						25
						26
						27
7,019,931		184,184,711			159,173	28
						29
						30
						31
						32
						33
						34
						35
						36
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						39
						40
-21,532,487		546,502,349			8,322,893	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	33,505,144	(21,326,851)
State Sales Tax on Purchases	(504,923)	(200,871)
County Sales Tax on Purchases	(4,681)	(4,764)
	32,995,540	(21,532,487)

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	12/31/2006	End of 2006/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%	29,796,508			4114001	6,410,000	
6							
7							
8	TOTAL	29,796,508				6,410,000	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
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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) 12/31/2006	Year/Period of Report End of 2006/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
23,386,508	27 years		5
			6
			7
23,386,508			8
			9
			10
			11
			12
			13
			14
			15
			16
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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	12/31/2006	End of 2006/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $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	1,268,999	131	576,449	89,411	781,961
2	Wholesale Deposits - SECI	5,350,000			1,780,000	7,130,000
3	Wholesale Deposits - Mirant	6,000,000				6,000,000
4	Wholesale Deposits - Other	118,859	242	531	114,614	232,942
5	Wholesale Deposits - FMPA	990,000			330,000	1,320,000
6	Derivative Premiums	43,151,300	131	52,902,700	9,751,400	
7	Deferred Rent Expenses	469,361	931	157,158	3	312,206
8	Cable and Other Deposits	365,298	131	48,500	222,063	538,861
9	Collateral Held Oil Swap	18,380,000	131	129,896,000	111,516,000	
10	Franchise Settlements	2,442,000	131, 242	604,000		1,838,000
11	Grid Florida RTO Recoveries	5,817,388	141, 186	5,820,441	3,053	
12	St. Pete Land Commitment	1,700,000	105	1,700,000		
13	Joint Owner	441,906	various	6,209,517	6,048,960	281,349
14	Various	122,387	various	5,196,765	5,178,371	103,993
15	PTC Fiber 400 Indemnification		242	537,660	8,361,787	7,824,127
16	AV Lease Incentive		242	710	275,962	275,252
17						
18						
19						
20						
21						
22						
23						
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36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	86,617,498		203,650,431	143,671,624	26,638,691

Schedule Page: 269 Line No.: 21 Column: a

Beginning balance is $6,513,980 less than reported in 2005 due to reclassification of Winter Park Stranded Costs.

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	12/31/2006	End of 2006/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	5,190,000		
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	5,190,000		
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)	5,190,000		
18	Classification of TOTAL			
19	Federal Income Tax	4,454,000		
20	State Income Tax	736,000		
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
				283	996,000	6,186,000	4
							5
							6
							7
					996,000	6,186,000	8
							9
							10
							11
							12
							13
							14
							15
							16
					996,000	6,186,000	17
							18
					850,000	5,304,000	19
					146,000	882,000	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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	438,183,791	29,398,000	16,892,000
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	438,183,791	29,398,000	16,892,000
6	Other			
7	Other			
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	438,183,791	29,398,000	16,892,000
10	Classification of TOTAL			
11	Federal Income Tax	376,921,562	25,172,000	14,496,000
12	State Income Tax	61,262,229	4,226,000	2,396,000
13	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) 12/31/2006	Year/Period of Report End of 2006/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
270,000	489,000	283	10,019,791			440,451,000	2
							3
							4
270,000	489,000		10,019,791			440,451,000	5
							6
							7
							8
270,000	489,000		10,019,791			440,451,000	9
							10
232,000	418,000		9,057,562			378,354,000	11
38,000	71,000		962,229			62,097,000	12
							13

NOTES (Continued)

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Assets - FAS 109	41,990,000	550,000	
4				
5				
6	OCI / Min. Pen. Liab.- Reclass	12,978,892		
7				
8	Other	123,341,893	120,018,363	133,609,679
9	TOTAL Electric (Total of lines 3 thru 8)	178,310,785	120,568,363	133,609,679
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)	178,310,785	120,568,363	133,609,679
20	Classification of TOTAL			
21	Federal Income Tax	153,014,407	103,234,978	114,537,201
22	State Income Tax	25,296,378	17,333,385	19,072,478
23	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) 12/31/2006	Year/Period of Report End of 2006/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						42,540,000	3
							4
							5
		190	12,978,892				6
							7
-468,797		281	996,000	190	162,617,129	270,902,909	8
-468,797			13,974,892		162,617,129	313,442,909	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
-468,797			13,974,892		162,617,129	313,442,909	19
							20
-401,957			11,978,369		139,537,984	268,869,842	21
-66,840			1,996,523		23,079,145	44,573,067	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $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 (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Accumulated Deferred Taxes - FAS 109	50,191,516	4111000	7,799,000	3,869,000	46,261,516
2	Period of Amortization occurs as					
3	temporary differences occur.					
4						
5	ARO - Nuclear Decom Trust Unr Gains	115,742,164	1289191	12,909,506	55,995,485	158,828,143
6	ARO - SFAS 143 Nuclear Decom	76,573,307	4073002	15,729,975	23,668,943	84,512,275
7	ARO - SFAS 143 Asbestos	3,743,818	4073002	1,746,704	1,214,876	3,211,990
8						
9	Deferred Fuel Revenue		5572002	35,780,612	111,510,539	75,729,927
10						
11	Deferred GPIF Liability - 1/07 - 12/07				1,547,048	1,547,048
12						
13	Auctioned S02 Allowance	4,120,393			1,995,298	6,115,691
14						
15	Derivative MTM Oil	122,409,306	1763015-17	1,175,599,110	1,053,189,804	
16						
17	Winter Park Stranded Costs-6/05-12/10	6,513,980	4560001	2,033,004		4,480,976
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	379,294,484		1,251,597,911	1,252,990,993	380,687,566

Schedule Page: 278 Line No.: 21 Column: a

Beginning balance is $6,513,980 greater than reported in 2005 due to the reclassification of Winter Park Stranded Costs.

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	12/31/2006	End of 2006/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

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	2,360,716,289	2,000,607,080
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,151,511,214	948,550,111
5	Large (or Ind.) (See Instr. 4)	345,703,073	284,365,436
6	(444) Public Street and Highway Lighting	2,002,621	1,645,750
7	(445) Other Sales to Public Authorities	299,096,915	240,205,452
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,159,030,112	3,475,373,829
11	(447) Sales for Resale	321,091,934	345,510,905
12	TOTAL Sales of Electricity	4,480,122,046	3,820,884,734
13	(Less) (449.1) Provision for Rate Refunds	898,573	2,289,386
14	TOTAL Revenues Net of Prov. for Refunds	4,479,223,473	3,818,595,348
15	Other Operating Revenues		
16	(450) Forfeited Discounts	22,682,285	10,615,943
17	(451) Miscellaneous Service Revenues	27,106,754	23,990,748
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	73,410,503	63,360,062
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-42,516,287	47,440,245
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	80,683,255	145,406,998
27	TOTAL Electric Operating Revenues	4,559,906,728	3,964,002,346

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
20,020,717	19,893,534	1,431,742	1,397,013	2
				3
11,975,026	11,944,716	162,774	161,001	4
4,160,024	4,139,872	2,697	2,703	5
26,650	27,388	1,748	1,795	6
3,249,420	3,171,076	21,412	20,879	7
				8
				9
39,431,837	39,176,586	1,620,373	1,583,391	10
4,532,942	5,456,086	23	26	11
43,964,779	44,632,672	1,620,396	1,583,417	12
				13
43,964,779	44,632,672	1,620,396	1,583,417	14

Line 12, column (b) includes $ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Service	20,020,717	2,360,716,289	1,431,742	13,983	0.1179
2						
3	Commercial and Industrial Service	16,135,050	1,497,214,287	165,471	97,510	0.0928
4						
5	Public Street and Highway					
6	Lighting	26,650	2,002,621	1,748	15,246	0.0751
7						
8	Other Sales to Public					
9	Authorities	3,249,420	299,096,915	21,412	151,757	0.0920
10						
11	Total Sales to Ultimate	39,431,837	4,159,030,112	1,620,373	24,335	0.1055
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	REQUIREMENT SERVICE					
2	CITY OF BARTOW	RQ	TARIFF NO. 9	57	57	55
3	CITY OF CHATTAHOOCHEE	RQ	FERC NO. 126	6	6	5
4	CITY OF HOMESTEAD	RQ	TARIFF NO. 9	15	15	15
5	CITY OF KISSIMMEE	RQ	FERC NO. 120			
6	CITY OF MOUNT DORA	RQ	FERC NO. 127	19	19	19
7	CITY OF NEWBERRY	RQ	FERC NO. 116	6	6	6
8	CITY OF NEW SMYRNA BEACH	RQ	FERC NO. 144	15	15	15
9	CITY OF QUINCY	RQ	TARIFF NO. 1	20	20	17
10	CITY OF ST CLOUD	RQ	FERC NO. 121			
11	CITY OF TALLAHASSEE	RQ	FERC NO. 178	14	14	14
12	CITY OF WILLISTON	RQ	FERC NO. 124	7	7	7
13	CITY OF WINTER PARK	RQ	FERC NO. 191	84	84	82
14	FLORIDA MUNICIPAL POWER AGENCY	RQ	FERC NO. 107	31	24	24
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
303,773	6,458,675	15,435,896	18,720	21,913,291	2
32,706	646,468	1,693,079	3,168	2,342,715	3
131,400	2,520,000	4,187,290		6,707,290	4
			8,004	8,004	5
102,751	2,242,217	5,260,635	3,168	7,506,020	6
2,611	62,942	169,387	264	232,593	7
104,502	2,010,360	4,315,328	996	6,326,684	8
115,338	2,249,417	5,992,079	6,336	8,247,832	9
			996	996	10
121,811	57,238	5,038,006		5,095,244	11
34,786	758,062	1,779,526	3,168	2,540,756	12
465,317	8,379,598	22,751,760		31,131,358	13
148,757	4,485,988	6,790,875	71,040	11,347,903	14
4,220,179	94,324,035	206,616,176	1,054,152	301,994,363	
312,763	0	19,204,050	-106,479	19,097,571	
4,532,942	**94,324,035**	**225,820,226**	**947,673**	**321,091,934**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	FLORIDA POWER AND LIGHT	RQ	TARIFF No. 9			
2	REEDY CREEK IMPROVEMENT DISTRICT	RQ	FERC NO. 118	69	69	69
3	SEMINOLE ELECTRIC COOPERATIVE, INC	RQ	FERC NO. 106	593	655	605
4	SOUTHEASTERN POWER ADMIN	RQ	FERC NO. 65	10	11	6
5	TAMPA ELECTRIC COMPANY	RQ	FERC NO. 7	62	62	62
6						
7						
8						
9	NON-REQUIREMENTS SERVICE					
10	ALABAMA ELECTRIC CO-OP	OS	FERC NO. 148			
11	CONOCO PHILLIPS	OS	FERC NO.10			
12	COBB ELECTRIC MEMBERSHIP CORP	OS	FERC NO. 10			
13	CARGILL-ALLIANT	OS	FERC NO. 8			
14	DTE ENERGY TRADING	OS	FERC NO. 176			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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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.
					1
553,640	9,285,500	19,573,655	33,984	28,893,139	2
1,596,001	44,689,555	95,228,122	904,308	140,821,985	3
35,521	288,015	1,503,238		1,791,253	4
471,265	10,190,000	16,897,300		27,087,300	5
					6
					7
					8
					9
25		1,456		1,456	10
348		27,613		27,613	11
19,665		1,015,989		1,015,989	12
79		7,754		7,754	13
					14
4,220,179	94,324,035	206,616,176	1,054,152	301,994,363	
312,763	0	19,204,050	-106,479	19,097,571	
4,532,942	**94,324,035**	**225,820,226**	**947,673**	**321,091,934**	

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	12/31/2006	End of 2006/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	DUKE POWER COMPANY	OS	FERC NO. 10			
2	FLORIDA MUNICIPAL POWER AGENCY	OS	FERC NO. 105			
3	FLORIDA POWER & LIGHT CO	OS	FERC NO. 81/02			
4	GAINESVILLE REGIONAL UTILITIES	OS	FERC NO. 88			
5	HOMESTEAD, CITY OF	OS	FERC NO. 82			
6	LAKELAND, CITY OF	OS	FERC NO 92			
7	NEW SMYRNA BEACH, CITY OF (1)	OS	FERC NO. 104			
8	OGLETHORPE	OS	FERC NO. 139			
9	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86			
10	PJM INTERCONNECTION, LLC	OS	PJM			
11	REEDY CREEK UTILITIES (1)	OS	FERC NO. 119			
12	SOUTH CAROLINA ELEC & GAS CO	OS	FERC NO. 8/10			
13	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128			
14	SOUTHERN COMPANY SERVICES	OS	FERC NO. 111			
	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.
					1
10,435		703,136		703,136	2
7,092		373,721		373,721	3
75		14,930		14,930	4
64		3,331		3,331	5
525		30,309		30,309	6
5,067		537,745	-53,127	484,618	7
1,540		102,598		102,598	8
1,000		42,774		42,774	9
25,449		1,616,618		1,616,618	10
5,874		305,943	-53,352	252,591	11
					12
121,955		8,431,864		8,431,864	13
6,030		316,528		316,528	14
4,220,179	94,324,035	206,616,176	1,054,152	301,994,363	
312,763	0	19,204,050	-106,479	19,097,571	
4,532,942	**94,324,035**	**225,820,226**	**947,673**	**321,091,934**	

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	12/31/2006	End of 2006/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	TALLAHASSEE, CITY OF	OS	FERC NO. 122			
2	THE ENERGY AUTHORITY	OS	FERC NO. 175			
3	TAMPA ELECTRIC CO	OS	FERC NO. 80			
4	TENNESSEE VALLEY AUTHORITY	OS	FERC NO. 138			
5	MORGAN STANLEY	OS	FERC NO. 177			
6						
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 Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
980		64,698		64,698	1
18,845		1,024,438		1,024,438	2
72,381		3,742,777		3,742,777	3
15,209		833,867		833,867	4
125		5,961		5,961	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
4,220,179	94,324,035	206,616,176	1,054,152	301,994,363	
312,763	0	19,204,050	-106,479	19,097,571	
4,532,942	**94,324,035**	**225,820,226**	**947,673**	**321,091,934**	

Schedule Page: 310.1 Line No.: 9 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.: 7 Column: a

2006 OS Sales for New Symrna Beach includes ($53,127) capacity credit.

Schedule Page: 310.2 Line No.: 11 Column: a

2006 OS Sales for Reedy Creek includes ($53,352) capacity credit.

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	12/31/2006	End of 2006/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	1,440,326	1,541,810
5	(501) Fuel	791,379,344	792,443,798
6	(502) Steam Expenses	7,498,258	8,287,694
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	40,992	8,087
10	(506) Miscellaneous Steam Power Expenses	20,285,051	25,218,350
11	(507) Rents		
12	(509) Allowances	7,670,904	31,061,621
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	828,314,875	858,561,360
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,557,945	3,781,214
16	(511) Maintenance of Structures	1,489,049	1,609,815
17	(512) Maintenance of Boiler Plant	9,997,882	9,310,082
18	(513) Maintenance of Electric Plant	4,269,282	4,415,005
19	(514) Maintenance of Miscellaneous Steam Plant	28,283,004	26,965,809
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	46,597,162	46,081,925
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	874,912,037	904,643,285
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	1,322,590	157,350
25	(518) Fuel	32,895,863	30,902,753
26	(519) Coolants and Water	3,739,552	3,607,835
27	(520) Steam Expenses	9,518,971	11,553,683
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	12,876	11,700
31	(524) Miscellaneous Nuclear Power Expenses	35,245,095	34,665,696
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	82,734,947	80,899,017
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	8,268,728	13,145,056
36	(529) Maintenance of Structures	6,328,529	897,761
37	(530) Maintenance of Reactor Plant Equipment	17,243,751	18,690,742
38	(531) Maintenance of Electric Plant	-2,416,100	2,482,936
39	(532) Maintenance of Miscellaneous Nuclear Plant	1,886,813	2,562,762
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	31,311,721	37,779,257
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	114,046,668	118,678,274
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	12/31/2006	End of 2006/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	8,190,817	14,120,367
63	(547) Fuel	620,689,433	665,406,008
64	(548) Generation Expenses	4,996,344	4,341,600
65	(549) Miscellaneous Other Power Generation Expenses	6,526,498	6,919,354
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	640,403,092	690,787,329
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	722,439	382,150
70	(552) Maintenance of Structures	143,890	182,878
71	(553) Maintenance of Generating and Electric Plant	2,811,679	1,827,297
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	11,830,952	9,338,883
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	15,508,960	11,731,208
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	655,912,052	702,518,537
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	762,324,823	714,065,625
77	(556) System Control and Load Dispatching	3,883,931	5,755,496
78	(557) Other Expenses	22,337	44,086
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	766,231,091	719,865,207
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,411,101,848	2,445,705,303
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,968,427	2,204,862
84	(561) Load Dispatching	923,610	410,477
85	(561.1) Load Dispatch-Reliability	594,292	
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	490,241	
87	(561.3) Load Dispatch-Transmission Service and Scheduling	925,994	
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	420,413	
90	(561.6) Transmission Service Studies	61,018	
91	(561.7) Generation Interconnection Studies	36,541	
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	303,199	352,674
94	(563) Overhead Lines Expenses	485,230	405,758
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	15,839,800	18,079,300
98	(567) Rents		
99	TOTAL Operation (Total of lines 83 thru 97)	22,048,765	21,453,071
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	28,892	
104	(569.2) Maintenance of Computer Software	72,347	
105	(569.3) Maintenance of Communication Equipment	28,893	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,900,120	1,653,870
108	(571) Maintenance of Overhead Lines	7,071,529	7,238,079
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	4,224,614	1,998,892
111	TOTAL Maintenance (Total of lines 101 thru 110)	14,326,395	10,890,841
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	36,375,160	32,343,912

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	12/31/2006	End of 2006/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	8,708,268	8,573,917
135	(581) Load Dispatching	3,998,893	3,946,840
136	(582) Station Expenses	496,843	494,031
137	(583) Overhead Line Expenses	1,413,089	1,318,912
138	(584) Underground Line Expenses	-116,945	1,275,124
139	(585) Street Lighting and Signal System Expenses	3,746,958	4,085,711
140	(586) Meter Expenses	7,327,345	6,439,872
141	(587) Customer Installations Expenses	431,209	598,214
142	(588) Miscellaneous Expenses	37,012,597	34,483,616
143	(589) Rents	3,329,469	3,286,262
144	TOTAL Operation (Enter Total of lines 134 thru 143)	66,347,726	64,502,499
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,208,935	1,866,021
147	(591) Maintenance of Structures	131,795	41,130
148	(592) Maintenance of Station Equipment	2,575,087	2,282,389
149	(593) Maintenance of Overhead Lines	31,190,330	44,201,168
150	(594) Maintenance of Underground Lines	9,869,250	9,655,614
151	(595) Maintenance of Line Transformers	555,542	118,994
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters	823,927	638,647
154	(598) Maintenance of Miscellaneous Distribution Plant	15,947,716	8,051,040
155	TOTAL Maintenance (Total of lines 146 thru 154)	63,302,582	66,855,003
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	129,650,308	131,357,502
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,300,976	1,225,085
160	(902) Meter Reading Expenses	5,393,606	10,006,780
161	(903) Customer Records and Collection Expenses	26,074,571	24,435,177
162	(904) Uncollectible Accounts	13,114,059	9,639,255
163	(905) Miscellaneous Customer Accounts Expenses	4,472,786	8,627,153

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	12/31/2006	End of 2006/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)
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	50,355,998	53,933,450
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	870,292	711,996
168	(908) Customer Assistance Expenses	60,070,737	60,193,967
169	(909) Informational and Instructional Expenses	3,733,319	2,905,644
170	(910) Miscellaneous Customer Service and Informational Expenses	33,003	64,274
171	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	64,707,351	63,875,881
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		13,152
175	(912) Demonstrating and Selling Expenses	1,819,546	1,990,109
176	(913) Advertising Expenses	1,566	31,045
177	(916) Miscellaneous Sales Expenses	542,791	329,976
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	2,363,903	2,364,282
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	50,064,147	56,148,675
182	(921) Office Supplies and Expenses	37,970,774	31,422,436
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	35,260,718	30,647,789
185	(924) Property Insurance	10,256,730	10,496,182
186	(925) Injuries and Damages	6,124,390	18,199,749
187	(926) Employee Pensions and Benefits	45,456,955	145,835,191
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	160,314	-54
190	(929) (Less) Duplicate Charges-Cr.	749,146	433,114
191	(930.1) General Advertising Expenses	1,402,110	2,237,206
192	(930.2) Miscellaneous General Expenses	2,020,834	5,394,047
193	(931) Rents	6,880,813	6,273,692
194	TOTAL Operation (Enter Total of lines 181 thru 193)	194,848,639	306,221,799
195	Maintenance		
196	(935) Maintenance of General Plant	-4,587,787	8,908,433
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	190,260,852	315,130,232
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,884,815,420	3,044,710,562

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	12/31/2006	End of 2006/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	127	154	132
5	AUBURNDALE POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
6	BAY COUNTY(1)	OS	COG	8	10	8
7	BAY COUNTY (1)	AD	COG	N/A	N/A	N/A
8	CARGILL FERTILIZER (1)	OS	COG	15	44	14
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	15	11
	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	12/31/2006	End of 2006/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
45,641				1,495,826		1,495,826	2
166				19,469		19,469	3
610,185			37,021,131	24,016,794		61,037,925	4
					-101,005	-101,005	5
70,502			3,165,360	1,706,307		4,871,667	6
							7
60,617			6,339,600	1,935,051		8,274,651	8
					-93,522	-93,522	9
35				4,297		4,297	10
							11
							12
							13
87,983			6,029,730	2,176,220		8,205,950	14
10,383,009	23,420		364,518,174	397,152,765	653,884	762,324,823	

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	12/31/2006	End of 2006/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	LAKE COUNTY (1)	AD	COG	N/A	N/A	N/A
2	LAKE COGEN LIMITED (1)	OS	COG	105	115	106
3	LAKE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
4	DADE COUNTY (1)	OS	COG	37	51	36
5	DADE COUNTY (1)	AD	COG	N/A	N/A	N/A
6	ORANGE COGEN LIMITED (1)	OS	COG	75	106	93
7	ORANGE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
8	ORLANDO COGEN LIMITED (1)	OS	COG	78	124	121
9	ORLANDO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
10	PASCO COGEN LIMITED (1)	OS	COG	101	111	95
11	PASCO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
12	PASCO COUNTY (1)	OS	COG	20	25	17
13	PASCO COUNTY (1)	AD	COG	N/A	N/A	N/A
14	PCS PHOSPHATE (1)	OS	COG	N/A	35	20
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
					-4,421	-4,421	1
436,149			31,975,807	20,174,907		52,150,714	2
					-751,085	-751,085	3
304,352			10,992,240	13,120,233		24,112,473	4
					-200,332	-200,332	5
336,311			27,318,197	12,564,022		39,882,219	6
					244,477	244,477	7
679,033			24,090,792	28,437,142		52,527,934	8
-357					341,692	341,692	9
443,090			37,996,612	15,026,942		53,023,554	10
					98,787	98,787	11
174,298			10,877,160	4,316,693		15,193,853	12
					-9,392	-9,392	13
173,209				10,540,781		10,540,781	14
10,383,009	23,420		364,518,174	397,152,765	653,884	762,324,823	

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	12/31/2006	End of 2006/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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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.

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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.

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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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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	50
3	PINELLAS COUNTY (1)	AD	COG	N/A	N/A	N/A
4	POLK POWER PARTNERS (1)	OS	COG	109	123	90
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	35	41	32
9	RIDGE GENERATING STATION (1)	AD	COG	N/A	N/A	N/A
10	SI GROUP ENERGY	OS	COG	N/A	3	2
11	INTERCHANGE POWER:					
12	CHATTAHOOCHEE, CITY OF	OS				
13	CHATTAHOOCHEE, CITY OF	AD				
14	COBB ELECTRIC MEMBERSHIP CORP.	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	12/31/2006	End of 2006/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)	
2,864					105,159	105,159	1
414,614			25,892,370	11,096,615		36,988,985	2
					-23,286	-23,286	3
415,051			45,995,223	12,713,534		58,708,757	4
					54,251	54,251	5
							6
					-43,838	-43,838	7
183,932			9,474,192	7,378,027		16,852,219	8
-15					-88,803	-88,803	9
2,071				91,519		91,519	10
							11
			157,136			157,136	12
					8,064	8,064	13
318,605				19,959,975		19,959,975	14
10,383,009	23,420		364,518,174	397,152,765	653,884	762,324,823	

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	12/31/2006	End of 2006/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	CAROLINA PWR. & LIGHT CO.	OS	FERC NO. 5			
2	CAROLINA PWR. & LIGHT CO.	AD	FERC NO. 5			
3	CALPINE ENERGY SVCS., L.P.	OS	FERC NO. 170			
4	CARGILL-ALLIANT, LLC	OS				
5	CENTRAL POWER & LIME	OS				
6	CENTRAL POWER & LIME	AD				
7	DUKE ENERGY TRADING	OS				
8	FLORIDA POWER & LIGHT CO.	OS	FERC NO. 81			
9	FLORIDA POWER & LIGHT CO.	AD	FERC NO. 81			
10	FLORIDA MUNICIPAL POWER AGENCY	OS				
11	GEORGIA POWER	OS				
12	GEORGIA TRANSMISSION CORP	OS				
13	GEORGIAN TRANSMISSION CORP	AD				
14	HOMESTEAD, CITY OF	OS	FERC NO. 82			
	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)	
				8,343		8,343	1
							2
13,428				855,164		855,164	3
61,068			500,000	4,006,118		4,506,118	4
845,249			16,292,088	27,047,966		43,340,054	5
					-172,145	-172,145	6
450				82,827		82,827	7
137,811			54,832	15,016,303		15,071,135	8
					-12,100	-12,100	9
234				22,200		22,200	10
							11
				32,742		32,742	12
					634	634	13
191				8,439		8,439	14
10,383,009	23,420		364,518,174	397,152,765	653,884	762,324,823	

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	12/31/2006	End of 2006/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	JACKSONVILLE ELECTRIC AUTHORITY	OS	FERC NO. 91			
2	JACKSONVILLE ELECTRIC AUTHORITY	AD	FERC NO. 91			
3	LAKELAND, CITY OF	OS	FERC NO. 92			
4	NEW HOPE POWER PARTNERSHIP	OS				
5	NEW SMYRNA BEACH, CITY OF	OS	FERC NO. 104			
6	OGLETHORPE POWER CORP	OS	FERC NO. 139			
7	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86			
8	ORLANDO UTILITIES COMMISSION	AD	FERC NO. 86			
9	PJM INTERCONNECTION, LLC	OS				
10	PJM INTERCONNECTION, LLC	AD				
11	REEDY CREEK UTILITIES	OS	FERC NO. 119			
12	RELIANT ENERGY SERVICES INC.	OS	FERC NO. 167			
13	RELIANT ENERGY SERVICES, INC.	AD	FERC NO. 167			
14	RELIANT ENERGY FLORIDA	OS				
	Total					

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)	
				1,967,108		1,967,108	1
					116	116	2
925				55,800		55,800	3
14,339				1,681,681		1,681,681	4
					-53,127	-53,127	5
							6
71,142			862,500	11,216,380		12,078,880	7
					12,100	12,100	8
4,416				201,709		201,709	9
					33,670	33,670	10
8,559				748,405	-53,352	695,053	11
47,121				5,699,687		5,699,687	12
					234,516	234,516	13
158,987			4,042,971	14,121,898		18,164,869	14
10,383,009	23,420		364,518,174	397,152,765	653,884	762,324,823	

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	12/31/2006	End of 2006/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	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128			
2	SEMINOLE ELECTRIC COOP INC.	AD	FERC NO. 128			
3	SOUTHERN COMPANY SERVICES INC.	OS	FERC NO. 111			
4	SOUTHERN COMPANY SERVICES INC.	AD	FERC NO. 70			
5	SOUTH CAROLINA ELECTRIC & GAS CO	OS				
6	TALLAHASSEE, CITY OF	OS	FERC NO. 122			
7	TALLAHASSEE, CITY OF	AD	FERC NO. 122			
8	THE ENERGY AUTHORITY	OS	FERC NO. 175			
9	TAMPA ELECTRIC CO.	OS	FERC NO. 80			
10	TAMPA ELECTRIC CO.	AD	FERC NO. 80			
11	TENNESSEE VALLEY AUTHORITY	OS				
12	CONOCO PHILLIPS	OS				
13	CINCINATTI GAS & ELECTRIC	OS				
14	INADVERTENT INTERCHANGE (NET)	OS				
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
43,924	23,420			4,959,421		4,959,421	1
					-908	-908	2
3,673,294			56,304,279	82,376,225		138,680,504	3
					1,127,711	1,127,711	4
							5
515				877,340		877,340	6
					-134	-134	7
142,913			1,218,750	12,657,389		13,876,139	8
351,886			7,917,204	23,006,237		30,923,441	9
					157	157	10
				17,748		17,748	11
495				31,769		31,769	12
969				96,498		96,498	13
-17							14
10,383,009	23,420		364,518,174	397,152,765	653,884	762,324,823	

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	12/31/2006	End of 2006/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	MUNICIPAL ELECT AUTHORTITY OF GA	OS				
2	MERRILL LYNCH	OS				
3	WILLIAMS ENERGY MARKETING &	OS				
4	WESTAR ENERGY	OS				
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	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	12/31/2006	End of 2006/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)	
				665		665	1
600				33,000		33,000	2
38,309				2,932,219		2,932,219	3
7,865				617,130		617,130	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
10,383,009	23,420		364,518,174	397,152,765	653,884	762,324,823	

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 ($101,005).

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

OUT-OF-PERIOD ADJUSTMENT - CARGILL FERTILIZER - ENERGY ($93,522).

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

OUT-OF-PERIOD ADJUSTMENT - LAKE COUNTY - ENERGY ($4,421).

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

OUT-OF-PERIOD ADJUSTMENT - LAKE COGEN LIMITED - ENERGY ($751,085).

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

OUT-OF-PERIOD ADJUSTMENT - DADE COUNTY - ENERGY ($67,842) AND DEMAND ($132,490).

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

OUT-OF-PERIOD ADJUSTMENT - ORANGE COGEN LIMITED - ENERGY $244,477.

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

OUT-OF-PERIOD ADJUSTMENT - ORLANDO COGEN LIMITED - ENERGY $83,729 AND DEMAND $257,963.

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

OUT-OF-PERIOD ADJUSTMENT - PASCO COGEN LIMITED - ENERGY $98,787.

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

OUT-OF-PERIOD ADJUSTMENT - PASCO COUNTY - ENERGY ($9,392).

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

OUT-OF-PERIOD ADJUSTMENT - PCS PHOSPHATE - ENERGY $105,159.

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

OUT-OF-PERIOD ADJUSTMENT - PINELLAS COUNTY - ENERGY ($23,286).

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

OUT-OF-PERIOD ADJUSTMENT - POLK POWER PARTNERS - ENERGY $54,251.

Schedule Page: 326.2 Line No.: 7 Column: l

OUT-OF-PERIOD ADJUSTMENT - US AGRI-CHEMICALS CORPORATION - DEMAND ($43,838).

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

OUT-OF-PERIOD ADJUSTMENT - RIDGE GENERATING STATION - ENERGY ($54,063) AND DEMAND ($34,740).

Schedule Page: 326.2 Line No.: 13 Column: a

OUT-OF-PERIOD ADJUSTMENT - CITY OF CHATTAHOOCHEE $8064 CAPACITY

Schedule Page: 326.3 Line No.: 1 Column: a

Carolina Power & Light Co. dba Progress Energy Carolina & Florida Power Corp dba Progress Energy Florida are subsidiaries of Progress Energy.

Schedule Page: 326.3 Line No.: 6 Column: a

OUT-OF-PERIOD ADJUSTMENT CENTRAL POWER AND LIME ($172,145) CAPACITY

Schedule Page: 326.3 Line No.: 9 Column: a

OUT-OF-PERIOD ADJUSTMENT - FLORIDA MUNICIPAL POWER ASSOC. ($12100) ENERGY

Schedule Page: 326.3 Line No.: 13 Column: a

OUT-OF-PERIOD ADJUSTMENT GEORGIA TRANSMISSION CORP $634.48 ENERGY

Schedule Page: 326.4 Line No.: 2 Column: a

OUT-OF-PERIOD ADJUSTMENT JACKSONVILLE ELECTRIC AUTHORITY $115 ENERGY

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

OUT-OF-PERIOD ADJUSTMENT ORLANDO UTILITIES COMMISSION $12100 ENERGY

Schedule Page: 326.4 Line No.: 10 Column: a

OUT-OF-PERIOD ADJUSTMENT JACKSONVILLE ELECTRIC AUTHORITY $33,670 ENERGY

FOOTNOTE DATA

Schedule Page: 326.4 Line No.: 13 Column: a

OUT-OF-PERIOD ADJUSTMENT RELIANT ENERGY SERVICES $234,516 ENERGY

Schedule Page: 326.5 Line No.: 2 Column: a

OUT-OF-PERIOD ADJUSTMENT SEMINOLE ELECTRIC CORP ($908) ENERGY

Schedule Page: 326.5 Line No.: 4 Column: a

OUT-OF-PERIOD ADJUSTMENT SOUTHERN COMPANY $42,977 CAPACITY & $1,084,734 ENERGY

Schedule Page: 326.5 Line No.: 7 Column: a

OUT-OF-PERIOD ADJUSTMENT CITY OF TALLAHASSEE ($134) ENERGY

Schedule Page: 326.5 Line No.: 10 Column: a

OUT-OF-PERIOD ADJUSTMENT TAMPA ELECTRIC CORP $157 ENERGY

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	12/31/2006	End of 2006/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	Progress Energy Florida	City of Alachua	LFP
2	Calpine Energy Services	Various	Various	NF
3	Cargill-Alliant	Various	Various	NF
4	Central Power & Lime	Central Power & Lime	Florida Power & Light	LFP
5	Cinergy Services	Various	Various	NF
6	Cobb Electric Membership	Various	Various	NF
7	City of Homestead	Progress Energy Florida	City of Homestead	NF
8	City of Homestead	Progress Energy Florida	City of Homestead	SFP
9	City of Tallahassee	City of Tallahassee	City of Tallahassee	LFP
10	City of Tallahassee	Progress Energy Florida	City of Tallahassee	LFP
11	City of Tallahassee	Various	Various	NF
12	Conoco Inc.	Various	Various	NF
13	Duke Energy Trading & Mkting	Various	Various	NF
14	Florida Power & Light Co.	Progress Energy Florida	Florida Power & Light	LFP
15	Florida Power & Light Co.	Progress Energy Florida	Florida Power & Light	SFP
16	Florida Power & Light Co.	Various	Various	NF
17	Florida Municipal Power Authority	Various	Various	NF
18	Gainesville Regional Utilities	Progress Energy Florida	Gainesville Regional	LFP
19	Georgia Power Company	Progress Energy Florida	Georgia Power Co.	AD
20	Georgia Power Company	Progress Energy Florida	Georgia Power Co.	OLF
21	City of Kissimmee	Progress Energy Florida	Kissimmee Utility Authority	LFP
22	City of Lakeland	Various	Various	NF
23	Oglethorpe Power Corp	Various	Various	NF
24	Orange Cogen LP	Orange Cogen LP	Tampa Electric Company	LFP
25	Orlando Utilities Commission	Progress Energy Florida	Orlando Utilities Commission	LFP
26	Orlando Utilities Commission	Various	Various	NF
27	Reedy Creek Improvement Dist.	Various	Various	NF
28	Reliant Energy Services	Reliant Energy Svcs	Florida Power & Light	LFP
29	Reliant Energy Services	Various	Various	NF
30	Seminole Electric Coop	Various	Various	NF
31	Seminole Electric Coop	Progress Energy Florida	Seminole Electric Coop	SFP
32	Southern Company of Florida	Various	Various	NF
33	Tampa Electric Company	Tampa Electric Company	Cities of Ft. Meade & Wachula	FNO
34	Tampa Electric Company	Progress Energy Florida	Tampa Electric Company	SFP
	TOTAL			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
T6/72	Crystal River Sub	Gainesville Regional	1		5,476	1
T6/106	Various	Various		2,596	2,530	2
T6/125C	Various	Various		24,796	24,254	3
T6/78	Brookridge Sub	FL Power & Light				4
T6/104	Various	Various		10,057	9,854	5
T6/114	Various	Various		14,736	14,429	6
T6/52	Various	FL Power & Light		131,902	129,257	7
T6/53	Various	FL Power & Light				8
T6/97	Jackson Bluff Sub	City of Tallahassee	11	10,160	9,936	9
T6/96	Progress Energy FL	City of Tallahassee	11	101,600	99,563	10
T6/19	Various	Various		132	129	11
T6/232C	Various	Various				12
T6/202C	Various	Various				13
T6/89	Progress Energy FL	FL Power & Light				14
T6/6C	Progress Energy FL	FL Power & Light				15
T6/7C	Various	Various				16
T6/31	Various	Various	19			17
T6/73	Crystal River Sub	Gainesville Regional	12	104,366	98,890	18
FERC No. 105	Intercession City Sb	Ga Power Company				19
FERC No. 105	Intercession City Sb	Ga Power Company	146			20
T6/74	Crystal River Sub	Kissimmee Utility	6	47,226	47,226	21
T6/56	Various	Various		7,315	7,181	22
T6/187C	Various	Various		196	192	23
T6/77	Orange Sub	Tampa Electric Co	23	76,107	76,107	24
T6/76	Crystal River Sub	Orlando Utilities Cm	13	111,957	111,957	25
T6/10	Various	Various		10,071	9,865	26
T6/14	Various	Various		12,031	11,801	27
T6/92	Hudson Sub	FL Power & Light	474	306,216	300,110	28
T6/3	Various	Various		71,916	70,498	29
T6/23	Various	Various		58,786	57,577	30
T6/24	Progress Energy FL	Seminole Electric Co	14			31
T6/29C	Various	Various				32
T6/98	Tampa Electric Co.	Ft. Meade & Wachula				33
T6/25	Progress Energy FL	Tampa Electric Co.		421,917	414,618	34
			737	**1,852,651**	**1,824,153**	

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	12/31/2006	End of 2006/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
8,861			8,861	2
71,978			71,978	3
3,579			3,579	4
149,932			149,932	5
44,311			44,311	6
183,490			183,490	7
				8
152,929			152,929	9
163,202			163,202	10
664			664	11
308			308	12
				13
126			126	14
				15
8,865			8,865	16
				17
142,163			142,163	18
				19
592,344			592,344	20
68,141			68,141	21
17,167			17,167	22
2,360			2,360	23
318,363			318,363	24
161,997			161,997	25
24,190			24,190	26
22,354			22,354	27
6,129,980			6,129,980	28
115,245			115,245	29
98,506			98,506	30
175,567			175,567	31
3,291			3,291	32
341,515			341,515	33
1,041,674			1,041,674	34
39,149,584	**0**	**0**	**39,149,584**	

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	12/31/2006	End of 2006/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	Various	Various	NF
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 New Smyrna Beach	Progress Energy Florida	Utilities Commission of NSB	LFP
6	City of New Smyrna Beach	Various	Various	SFP
7	City of New Smyrna Beach	Various	Various	NF
8	City of Winter Park	Progress Energy Florida	City of Winter Park	FNO
9	Progress Ventures	Various	Various	NF
10	Rainbow Energy Marketing	Various	Various	NF
11	Reedy Creek Imporvement Dist.	Various	Various	OS
12	Seminole Electric Cooperative Inc.	Various	Various	OS
13	Florida Municipal Power Authority	Various	Various	OS
14	Southeastern Power Admin	Various	Various	OS
15	PJM	Various	Various	NF
16	Tennessee Valley Authority	Various	Various	NF
17	Alabama Electric Coop	Various	Various	NF
18	Morgan Stanley Capital Group	Various	Various	NF
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	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	12/31/2006	End of 2006/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.
T6/160C	Various	Various		19,513	19,112	1
T6/116	Archer Sub	Gainesville Regional	2	3,436	3,368	2
T6/62	Various	Various				3
T6/68C	Various	Various		250,124	245,043	4
T6/75	Crystal River Sub	New Smyrna Beach	5	39,208	39,208	5
T6/13	Various	Various				6
T6/12	Various	Various		13,582	13,309	7
T6/124	Various	City of Winter Park		995	974	8
T6/208C	Various	Various		102	102	9
T6/35C	Various	Various		1,608	1,587	10
T6	Various	Various				11
T6	Various	Various				12
T6/31	Various	Various				13
T6	Various	Various				14
T6	Various	Various				15
T6/70	Various	Various				16
T6	Various	Various				17
T6	Various	Various				18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			737	**1,852,651**	**1,824,153**	

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	12/31/2006	End of 2006/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.
6,100			6,100	1
36,604			36,604	2
				3
633,545			633,545	4
58,670			58,670	5
				6
24,880			24,880	7
1,351,149			1,351,149	8
5,448			5,448	9
8,343			8,343	10
1,487,058			1,487,058	11
20,491,535			20,491,535	12
4,723,371			4,723,371	13
205,660			205,660	14
57,937			57,937	15
8,190			8,190	16
21			21	17
107			107	18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
39,149,584	**0**	**0**	**39,149,584**	

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	12/31/2006	End of 2006/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	464,676
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	-179,038
7	Service Company Allocations	375,756
8	Fleet Transportation Clearing	-385,523
9	Stores Burden Adjustment	444,963
10	Inventory Adjustment	1,300,000
11		
12		
13		
14		
15		
16		
17		
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45		
46	TOTAL	2,020,834

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	12/31/2006	End of 2006/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			13,829,877		13,829,877
2	Steam Production Plant	50,227,970	310,733			50,538,703
3	Nuclear Production Plant	18,177,167	1,139			18,178,306
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	52,549,486				52,549,486
7	Transmission Plant	25,788,171				25,788,171
8	Distribution Plant	106,689,215				106,689,215
9	Regional Transmission and Market Operation					
10	General Plant	13,074,657	42,688	9,884		13,127,229
11	Common Plant-Electric					
12	TOTAL	266,506,666	354,560	13,839,761		280,700,987

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%

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	PROD PLANT - STEAM						
13	ANCLOTE						
14	311	37,648,936	55.00	-2.30	3.24	L2	13.10
15	312	105,924,086	48.91	-12.50	3.34	R1	12.70
16	314	98,038,271	51.14	-3.30	2.31	L0.5	12.80
17	315	26,471,333	53.45	-3.00	1.99	L0.5	12.70
18	316.1	6,238,486	39.40	-5.90	2.21	L0	11.80
19	316.2	121,812	39.40		20.00	L0	11.80
20	316.3	276,165	39.40	-5.90	14.30	L0	11.80
21	BARTOW						
22	311	18,231,332	53.61	-2.30	2.46	L2	10.30
23	312	62,821,739	47.68	-12.50	2.91	R1	10.00
24	314	26,266,315	49.61	-3.30	0.96	L0.5	10.00
25	315	13,697,655	50.75	-3.00	1.22	L0.5	10.10
26	316.1	3,316,009	36.60	-5.90	3.19	L0	9.60
27	316.2	171,684	36.60		20.00	L0	9.60
28	316.3	350,367	36.60	-5.90	14.30	L0	9.60
29	BARTOW-ANCLOTE						
30	311	1,111,324	43.37	-2.30	3.07	L2	13.10
31	312	17,010,912	38.38	-12.50	4.10	R1	12.70
32	315	1,252,617	39.90	-3.00	2.78	L0.5	12.60
33	316.1	152,597	31.78	-5.90	5.20	L0	11.90
34	316.3	8,731	31.78	-5.90	14.30	L0	11.90
35	CRYSTAL RIVER 1&2						
36	311	74,893,485	49.12	-2.30	2.57	L2	12.30
37	312	166,951,448	46.79	-12.50	4.03	R1	11.90
38	312 - Rail Cars	18,512,769	20.00	-3.00	4.85	N/A	
39	312.9	1,023,482	42.67	-15.00	0.54	R1	11.30
40	314	123,723,197	50.64	-3.30	3.06	L0.5	12.00
41	315	35,096,172	44.68	-3.00	2.88	L0.5	12.00
42	316.1	6,033,538	36.98	-5.90	3.19	L0	11.20
43	316.2	149,408	36.98		20.00	L0	11.20
44	316.3	147,184	36.98	-5.90	14.30	L0	11.20
45	CRYSTAL RIVER 4&5						
46	311	149,196,853	62.31	-2.30	3.39	L2	15.00
47	312	471,112,042	36.37	-12.50	2.83	R1	14.40
48	312 - Rail Cars	18,512,769	20.00	-3.00	4.85	N/A	
49	312.9	1,727,433	32.79	-15.00	0.55	R1	14.40
50	314	192,896,954	37.24	-3.30	2.14	L0.5	14.40

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	315	80,592,235	37.72	-3.00	2.78	L0.5	14.60
13	316.1	11,536,925	34.44	-5.90	3.27	L0	13.40
14	316.2	233,211	34.44		20.00	L0	13.40
15	316.3	833,644	34.44	-5.90	14.30	L0	13.40
16	SUWANNEE						
17	311	5,064,160	59.49	-2.30	1.45	L2	10.10
18	312	14,841,041	48.11	-12.50	2.96	R1	10.00
19	314	11,093,136	49.61	-3.30	1.13	L0.5	10.00
20	315	2,719,876	55.46	-3.00	0.98	L0.5	10.00
21	316.1	439,403	36.79	-5.90	1.71	L0	9.30
22	316.2	7,170	36.79		20.00	L0	9.30
23	316.3	29,614	36.79	-5.90	14.30	L0	9.30
24	SYSTEM ASSETS						
25	316.2	558,132	5.00		20.00	N/A	
26	316.3	440,892	7.00		14.30	N/A	
27							
28	PROD PLANT-NUCLEAR						
29	CRYSTAL RIVER 3						
30	321	217,259,353	58.95	-10.40	1.78	L1.5	28.10
31	321.1	4,590,511	35.81	-10.40	2.81	L1.5	29.40
32	322	258,980,914	55.03	-18.90	2.24	R0.5	26.20
33	322.1	2,006,295	32.08	-18.90	3.36	R0.5	26.90
34	323	90,911,280	26.79	-20.82	2.97	L0.5	15.60
35	323.1	1,545,523	24.12	-15.53	4.31	L0.5	19.10
36	324	178,648,296	62.18	-2.70	1.28	R1.5	27.50
37	324.1	645,490	34.33	-2.70	2.68	R1.5	28.40
38	325	34,065,327	14.00	-10.00	5.54	L2	7.50
39	325.1	237,806	14.00	-10.00	7.08	L2	8.30
40	325.2	2,653,146	5.00		20.00	N/A	
41	325.3	4,283,442	7.00	-10.00	14.30	N/A	
42	OTHER PRODUCTION						
43	AVON PARK						
44	341	405,755	49.39	-0.60	0.69	L2	9.60
45	342	447,580	31.82	-6.30	3.49	R0.5	9.50
46	343	4,862,571	37.37	-4.80	1.32	R0.5	9.80
47	344	1,635,196	43.10	-0.70	2.68	R2	10.20
48	345	1,152,348	39.94	-3.50	1.46	S1	9.90
49	346	71,944	40.00	-5.60	1.80	R1	9.60
50	346.2	26,451	40.00		20.00	R1	9.60

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13	BARTOW						
14	341	1,074,388	38.40	-0.60	0.39	L2	9.40
15	342	1,697,829	30.66	-6.30	3.31	R0.5	9.30
16	343	13,221,342	35.18	-4.80	3.31	R0.5	9.90
17	344	6,826,658	40.20	-0.70	0.42	R2	10.00
18	345	2,133,581	37.87	-3.50	0.27	S1	9.40
19	346	144,659	34.19	-5.60	4.28	R1	9.90
20	346.2	1,925	34.19		20.00	R1	9.90
21	BAYBORO						
22	341	1,650,590	38.40	-0.60	2.90	L2	10.40
23	342	1,082,855	30.66	-6.30	2.66	R0.5	9.90
24	343	16,248,849	35.18	-4.80	2.63	R0.5	10.70
25	344	3,867,446	40.20	-0.70	3.53	R2	11.20
26	345	1,121,460	45.64	-3.50	0.87	S1	10.30
27	346	371,332	39.49	-5.60	3.04	R1	10.30
28	346.2	19,869	39.49		20.00	R1	10.30
29	DEBARY (OLD) P1-P6						
30	341	4,929,563	38.94	-0.60	2.71	L2	13.20
31	342	6,386,453	30.98	-6.30	2.33	R0.5	11.70
32	343	26,583,940	35.74	-4.80	3.39	R0.5	13.30
33	344	9,457,806	40.95	-0.70	1.45	R2	13.60
34	345	5,772,581	38.42	-3.50	1.63	S1	12.70
35	346	592,871	34.64	-5.60	2.98	R1	12.80
36	346.2	25,737	34.64		20.00	R1	12.80
37	DEBARY (NEW) P7-P10						
38	341	4,714,633	29.51	-0.60	3.57	L2	16.50
39	342	6,915,510	24.82	-6.30	4.48	R0.5	15.00
40	343	63,692,381	26.82	-4.80	4.43	R0.5	16.00
41	344	18,413,683	29.55	-0.70	3.71	R2	16.80
42	345	5,110,760	29.07	-3.50	3.80	S1	16.20
43	346	834,978	37.48	-5.60	4.94	R1	16.00
44	346.2	21,284	37.48		20.00	R1	16.00
45	HIGGINS						
46	341	791,388	40.46	-0.60	0.20	L2	9.60
47	342	1,542,983	31.56	-6.30	5.57	R0.5	9.60
48	343	10,283,743	36.82	-4.80	1.00	R0.5	9.80
49	344	2,654,287	42.40	-0.70	0.20	R2	10.10
50	345	2,441,137	39.45	-3.50		S1	9.80

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	346	116,970	35.85	-5.60	3.90	R1	9.90
13	346.2	15,197	35.85		20.00	R1	9.90
14	HINES CMPLX 1						
15	341	42,347,351	33.33	-0.60	2.15	L2	23.10
16	342	14,763,570	27.44	-6.30	4.73	R0.5	20.10
17	343	161,447,673	30.27	-4.80	3.18	R0.5	21.70
18	344	44,807,805	33.84	-0.70	3.35	R2	23.30
19	345	20,548,294	32.80	-3.50	2.59	S1	22.70
20	346	3,405,964	29.97	-5.60	4.03	R1	21.40
21	346.2	26,113	29.97		20.00	R1	21.40
22	HINES CMPLX 2						
23	341	12,418,978	28.69	-0.60	3.57	L2	26.20
24	343	78,822,172	26.10	-4.80	4.12	R0.5	24.10
25	344	99,653,854	28.67	-0.70	3.62	R2	26.30
26	345	44,449,318	28.27	-3.50	3.79	S1	25.80
27	346	3,828,774	26.07	-5.60	4.18	R1	24.00
28	HINES CMPLX 3						
29	341	11,657,217	30.00	-0.60	3.57	L2	28.20
30	342	14,311,691	30.00	-6.30	3.86	R0.5	29.00
31	343	154,015,716	30.00	-4.80	4.16	R0.5	25.70
32	344	48,334,660	30.00	-0.70	3.66	R2	28.20
33	345	21,273,707	30.00	-3.50	3.87	S1	27.80
34	346	3,286,501	30.00	-5.60	4.15	R1	25.70
35	INTERCESSION P1-P6						
36	341	3,660,217	38.94	-0.60	2.95	L2	12.60
37	342	1,668,967	30.98	-6.30	3.39	R0.5	11.40
38	343	23,434,238	35.74	-4.80	2.63	R0.5	12.30
39	344	4,716,975	40.95	-0.70	2.38	R2	12.90
40	345	3,292,138	44.61	-3.50	2.63	S1	12.40
41	346	666,684	34.64	-5.60	5.60	R1	12.60
42	INTERCESSION P7-P10						
43	341	9,423,437	29.51	-0.60	3.59	L2	17.40
44	342	7,506,654	24.82	-6.30	4.56	R0.5	15.70
45	343	60,998,124	27.53	-4.80	4.52	R0.5	16.80
46	344	17,702,413	29.55	-0.70	3.72	R2	17.80
47	345	5,257,047	29.07	-3.50	3.93	S1	17.20
48	346	1,075,045	26.76	-5.60	4.73	R1	16.80
49	INTERCESSION P11						
50	341	1,244,317	24.36	-0.60	4.13	L2	16.00

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	342	1,379,318	21.11	-6.30	5.12	R0.5	14.50
13	343	14,182,088	23.11	-4.80	4.68	R0.5	15.20
14	344	2,664,079	24.17	-0.70	4.15	R2	16.00
15	345	3,630,191	24.08	-3.50	4.32	S1	15.80
16	346	188,206	21.22	-5.60	5.67	R1	15.30
17	INTERCESSION P12						
18	341	1,426,366	26.13	-0.60	10.69	L2	20.70
19	342	5,838,131	22.41	-6.30	5.34	R0.5	18.30
20	343	60,728,953	23.87	-4.80	4.90	R0.5	19.40
21	344	16,681,378	25.99	-0.70	4.00	R2	20.70
22	345	6,911,508	25.80	-3.50	4.73	S1	20.40
23	346.2	48,968	23.91		20.00	R1	
24	RIO PINAR						
25	341	88,646	39.47	-0.60	1.46	L2	10.00
26	342	341,789	31.28	-6.30	1.13	R0.5	9.30
27	343	1,988,909	36.28	-4.80	2.45	R0.5	9.90
28	344	403,869	41.68	-0.70		R2	9.80
29	345	295,994	38.94	-3.50	0.89	S1	9.90
30	346	4,498	21.63	-5.60	1.94	R1	9.90
31	SUWANNEE						
32	341	1,471,200	34.72	-0.60	1.61	L2	11.40
33	342	2,366,801	28.36	-6.30	3.20	R0.5	10.90
34	343	18,351,232	31.57	-4.80	2.12	R0.5	11.50
35	344	5,021,099	35.49	-0.70	1.38	R2	12.00
36	345	1,881,552	34.18	-3.50	1.73	S1	11.50
37	346	131,399	31.14	-5.60	4.29	R1	11.60
38	TIGER BAY						
39	341	10,553,415	27.00	-0.60	2.82	L2	18.60
40	342	3,053,255	23.04	-6.30	4.73	R0.5	16.70
41	343	39,018,375	24.62	-4.80	2.54	R0.5	17.70
42	344	20,909,981	26.89	-0.70	4.20	R2	18.80
43	345	5,447,672	26.64	-3.50	2.19	S1	18.30
44	346	1,552,031	24.65	-5.60	4.33	R1	17.60
45	TURNER						
46	341	1,328,420	39.98	-0.60	3.20	L2	10.90
47	342	2,551,290	31.56	-6.30	1.83	R0.5	9.70
48	343	11,756,495	36.82	-4.80	2.74	R0.5	10.70
49	344	4,611,530	42.40	-0.70	0.90	R2	11.00
50	345	2,215,231	39.45	-3.50	2.23	S1	10.80

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	346	275,092	36.89	-5.60	4.82	R1	10.80
13	346.2	27,401	36.89		20.00	R1	10.80
14	UNIVERSITY OF						
15	341	6,499,783	21.60	-0.60	5.05	L2	10.30
16	342	5,951,874	19.03	-6.30	6.74	R0.5	9.70
17	343	18,970,166	19.96	-4.80	6.67	R0.5	10.00
18	344	3,561,068	21.39	-0.70	5.11	R2	10.30
19	345	5,513,891	21.41	-3.50	5.45	S1	10.20
20	346	995,623	20.05	-5.60	5.96	R1	9.90
21	346.2	35,411	20.05		20.00	R1	9.90
22	UNIV OF FLORIDA(118)						
23	341	2,531,240	21.60	-10.00	6.11	L2	10.30
24	SYSTEM ASSETS						
25	346	336,027	32.23	-5.60	3.52	R1	29.70
26	346.2	55,148	32.23		20.00	R1	29.70
27	GAS CONVERSION	1,032,024	5.00		20.00	N/A	
28	TRANSMISSION						
29	350.1	47,086,567	75.00		1.21	R3	56.50
30	352	22,994,504	60.00	-15.00	1.87	R2.5	42.50
31	353.1	435,302,337	52.00		1.78	R1	39.70
32	353.2	34,962,909	17.00		0.90	L2	8.10
33	354	66,449,362	58.00	-25.00	1.72	R4	26.00
34	355	329,543,595	40.00	-25.00	2.72	R1.5	30.80
35	356	234,465,538	48.00	-30.00	2.26	R2	33.10
36	357	7,009,407	55.00		1.28	R2.5	22.20
37	358	9,596,457	55.00	-3.00	1.13	R2.5	21.00
38	359	3,133,471	90.00		0.76	R2.5	63.80
39	DISTRIBUTION						
40	360.1	556,471	75.00		1.19	R3	54.50
41	361	23,852,837	55.00	-5.00	1.86	R2.5	40.90
42	362	385,489,525	45.00	-15.00	2.57	R1	33.30
43	364	462,218,961	28.00	-15.59	3.86	L4	17.40
44	365	507,004,986	33.00	-9.58	2.66	R2	22.70
45	366	190,332,425	55.00		1.78	R3	45.30
46	367	464,597,281	34.00	-6.00	3.19	R3	24.50
47	368	449,329,035	26.00	-3.53	3.38	R2.5	15.30
48	369.1	75,103,353	36.00	-24.95	2.86	R3	19.30
49	369.2	375,494,025	38.00	-3.94	2.76	R2.5	29.30
50	370	112,434,263	26.00	-8.00	3.57	R2.5	14.00

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	371	3,081,164	24.00		3.93	R2	16.00
13	373	268,254,136	17.00		4.59	L2	10.80
14							
15	GENERAL PLANT						
16	390	114,055,520	28.00		3.48	L0	22.50
17	391.1	5,723,865	7.00		14.30	N/A	
18	391.2	82,127	7.00		14.30	N/A	
19	391.3	3,490,918	5.00		20.00	N/A	
20	391.5	1,062,024	7.00		14.30	N/A	
21	393.1	3,152,492	7.00		14.30	N/A	
22	393.2	301,589	7.00		14.30	N/A	
23	393.3	3,893	7.00		14.30	N/A	
24	394	1,148,710	7.00		14.30	N/A	
25	394.1	7,393,170	7.00		14.30	N/A	
26	394.2	4,556,612	7.00		14.30	N/A	
27	395	13,052	7.00		14.30	N/A	
28	395.2	3,101,333	7.00		14.30	N/A	
29	396	4,007,389	17.00		5.81	N/A	
30	397	32,684,258	7.00		14.30	N/A	
31	397.1	26,732,035	7.00		14.30	N/A	
32	398	2,774,826	7.00		14.30	N/A	
33	398.1	49,419	5.00		20.00	N/A	
34	398.2	4,711,641	7.00		14.30	N/A	
35	TRANSPORTATION						
36	392.1	989,026			8.70	S2	2.60
37	392.2	21,302,640			8.70	L2	4.00
38	392.3	16,207,544			4.80	L4	7.00
39	392.4	97,364,407			5.00	S2	9.50
40	392.5	8,405,690			1.70	R2.5	18.80
41							
42	302	8,450,028	30.03		3.33	N/A	
43	303	62,290,514	5.00		20.00	N/A	
44	303	1,212,597	7.00		14.29	N/A	
45	303.1	58,702,686			10.00	N/A	
46							
47							
48							
49							
50							

Schedule Page: 336 Line No.: 3 Column: b

Depreciation rates do not include Nuclear Decommissioning, however, there is no longer an accrual for Progress Energy Florida related to decommissioning expense.

Schedule Page: 336 Line No.: 12 Column: a

Rates are Retail Rates Authorized by the Florida Public Service Commission in Docket No. 050078-EI, Order NO. PSC-05-0945-S-EI. Rates became effective 01/01/2006.

Depreciable Plant base represents end of period balances by each category which the company applies a separate depreciation rate. The normal monthly calculation is: (Base * Rate)/12.

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	12/31/2006	End of 2006/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				
2	fee for fiscal year 2006.	160,314		160,314	
3					
4					
5					
6					
7					
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45					
46	TOTAL	160,314		160,314	

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	12/31/2006	End of 2006/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
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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	12/31/2006	End of 2006/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	2006 Nuclear Power Program
5		
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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	12/31/2006	End of 2006/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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
					3
	464,675	930	464,675		4
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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	12/31/2006	End of 2006/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	57,103,744		
4	Transmission	13,092,062		
5	Regional Market			
6	Distribution	36,590,984		
7	Customer Accounts	20,391,177		
8	Customer Service and Informational	9,851,939		
9	Sales	1,291,882		
10	Administrative and General	43,168,937		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	181,490,725		
12	Maintenance			
13	Production	28,453,781		
14	Transmission	2,017,107		
15	Regional Market			
16	Distribution	18,218,808		
17	Administrative and General	276,156		
18	TOTAL Maint. (Total of lines 12 thru 17)	48,965,852		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	85,557,525		
21	Transmission (Enter Total of lines 4 and 14)	15,109,169		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	54,809,792		
24	Customer Accounts (Transcribe from line 7)	20,391,177		
25	Customer Service and Informational (Transcribe from line 8)	9,851,939		
26	Sales (Transcribe from line 9)	1,291,882		
27	Administrative and General (Enter Total of lines 10 and 17)	43,445,093		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	230,456,577	20,075,771	250,532,348
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	12/31/2006	End of 2006/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)	230,456,577	20,075,771	250,532,348
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	73,694,717		73,694,717
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	73,694,717		73,694,717
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	Stores Expense Undistrib	6,769,954	482,105	7,252,059
78	Clearing Accounts	5,544,586		5,544,586
79	Misc Deferred Debits	327,742		327,742
80				
81	All Other Accounts	9,755,901	3,272	9,759,173
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	22,398,183	485,377	22,883,560
96	TOTAL SALARIES AND WAGES	326,549,477	20,561,148	347,110,625

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	12/31/2006	End of 2006/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	697,440	MWH	10,493	385,951	MW Demand	661,582
2	Reactive Supply and Voltage	697,440	MWH	37,741	368,112	MW Demand	443,871
3	Regulation and Frequency Response				69,587	MW Demand	101,039
4	Energy Imbalance				86,911	MWH	-68,053
5	Operating Reserve - Spinning				993	MW Demand	42,570
6	Operating Reserve - Supplement				993	MW Demand	41,348
7	Other						
8	Total (Lines 1 thru 7)	1,394,880		48,234	912,547		1,222,357

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/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

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	10,865	19	800	7,133	89	593	3,000	50	
2	February	13,621	14	800	8,914	120	590	3,947	50	
3	March	8,603	21	2000	6,084	84	590	1,795	50	
4	Total for Quarter 1	33,089			22,131	293	1,773	8,742	150	
5	April	10,545	20	1800	7,436	107	590	2,362	50	
6	May	11,307	28	1600	7,741	106	590	2,820	50	
7	June	12,389	21	1700	8,501	114	590	3,134	50	
8	Total for Quarter 2	34,241			23,678	327	1,770	8,316	150	
9	July	12,382	26	1600	8,570	118	590	3,200	50	
10	August	12,665	10	1700	8,748	120	590	3,303	50	
11	September	11,483	25	1700	8,121	114	590	2,754	50	
12	Total for Quarter 3	36,530			25,439	352	1,770	9,257	150	
13	October	10,830	20	1700	7,750	104	590	2,336	50	
14	November	8,478	30	1900	5,951	79	590	1,808	50	
15	December	9,147	8	2100	6,030	73	590	2,404	50	
16	Total for Quarter 4	28,455			19,731	256	1,770	6,548	150	
17	Total Year to Date/Year	132,315			90,979	1,228	7,083	32,863	600	

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	12/31/2006	2006/Q4

FOOTNOTE DATA

Schedule Page: 400 Line No.: 9 Column: h

Georgia Power Peak Usage was not included when entering the totals in the 3rd Qtr.

Schedule Page: 400 Line No.: 10 Column: h

Georgia Power Peak Usage was not included when entering the totals in the 3rd Qtr.

Schedule Page: 400 Line No.: 11 Column: h

Georgia Power Peak Usage was not included when entering the totals for the 3rd Qtr.

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	12/31/2006	End of 2006/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	39,431,837
3	Steam	19,785,112			
4	Nuclear	6,382,175	23	Requirements Sales for Resale (See instruction 4, page 311.)	4,220,179
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	312,763
7	Other	9,751,385			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	35,918,672	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	164,778
10	Purchases	10,383,009	27	Total Energy Losses	2,224,042
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	46,353,599
12	Received	23,420			
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)	23,420			
15	Transmission For Other (Wheeling)				
16	Received	1,852,651			
17	Delivered	1,824,153			
18	Net Transmission for Other (Line 16 minus line 17)	28,498			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	46,353,599			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/Q4

MONTHLY PEAKS AND OUTPUT

(1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
(2) Report 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	3,402,428	12,104	7,869	19	800
30	February	3,222,808	32,022	10,094	14	800
31	March	3,325,063	39,548	6,440	21	2000
32	April	3,615,628	33,998	7,835	20	1800
33	May	4,081,560	61,292	8,381	28	1600
34	June	4,421,605	20,719	9,348	21	1700
35	July	4,720,904	21,984	9,461	26	1600
36	August	4,930,274	10,763	9,689	10	1700
37	September	4,276,355	6,548	8,793	25	1700
38	October	3,777,011	14,449	8,285	20	1700
39	November	3,222,654	29,419	6,414	30	1900
40	December	3,357,309	29,917	6,792	8	2100
41	TOTAL	46,353,599	312,763			

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	12/31/2006	End of 2006/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Anclote* (b)			Plant Name: *Bartow* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1974			1958		
4	Year Last Unit was Installed	1978			1963		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1112.40			494.36		
6	Net Peak Demand on Plant - MW (60 minutes)	1027			454		
7	Plant Hours Connected to Load	12737			19345		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1048			464		
10	When Limited by Condenser Water	1005			444		
11	Average Number of Employees	73			71		
12	Net Generation, Exclusive of Plant Use - KWh	2940530000			1594824000		
13	Cost of Plant: Land and Land Rights	1869309			2046939		
14	Structures and Improvements	37633452			19342656		
15	Equipment Costs	237273372			125298383		
16	Asset Retirement Costs	315962			1929969		
17	Total Cost	277092095			148617947		
18	Cost per KW of Installed Capacity (line 17/5) Including	249.0939			300.6270		
19	Production Expenses: Oper, Supv, & Engr	8943			526		
20	Fuel	191704816			105614044		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	66072			279984		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	552			22		
26	Misc Steam (or Nuclear) Power Expenses	4936419			3428213		
27	Rents	0			0		
28	Allowances	1380168			722517		
29	Maintenance Supervision and Engineering	805425			937102		
30	Maintenance of Structures	1229687			78032		
31	Maintenance of Boiler (or reactor) Plant	3932638			587658		
32	Maintenance of Electric Plant	2040394			123764		
33	Maintenance of Misc Steam (or Nuclear) Plant	5159156			2798294		
34	Total Production Expenses	211264270			114570156		
35	Expenses per Net KWh	0.0718			0.0718		
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	4565458	201268	0	2510831	575713	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	156796	1034	0	156932	1033	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	42.473	7.415	0.000	40.947	6.574	0.000
41	Average Cost of Fuel per Unit Burned	41.641	7.415	0.000	40.514	6.574	0.000
42	Average Cost of Fuel Burned per Million BTU	6.323	7.168	0.000	6.147	6.365	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.074	0.000	0.000	0.067	0.000
44	Average BTU per KWh Net Generation	0.000	10296.000	0.000	0.000	10505.000	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
876	1456	779	6
16401	15974	8221	7
0	0	0	8
882	1468	788	9
870	1443	769	10
131	197	526	11
5149092000	9865782000	6382175000	12
2512007	0	-150918	13
74893485	149212337	221849864	14
351762134	777616830	573977519	15
3683195	0	50846	16
432850821	926829167	795727311	17
448.8524	626.8628	893.6138	18
651778	777186	1322590	19
171604938	298431296	32895863	20
0	0	3739552	21
2761258	4167287	9518971	22
0	0	0	23
0	0	0	24
22	40375	12876	25
3744389	6099127	35245095	26
0	0	0	27
3821250	1552179	0	28
340091	415716	8268728	29
70067	49775	6328529	30
698719	4629717	17243751	31
771396	1225239	-2416100	32
11775518	7253755	1886813	33
196239426	324641652	114046668	34
0.0381	0.0329	0.0179	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Oil	Coal		Oil	Coal		Oil	Nuclear		36
BBL	Tons		BBL	Tons		BBL	MMBTU		37
19764	2112672	0	58690	3864515	0	457	65780814	0	38
132382	12339	0	138644	12221	0	137751	0	0	39
97.414	80.059	0.000	90.091	76.529	0.000	24.782	0.000	0.000	40
90.200	79.799	0.000	85.671	75.451	0.000	0.000	0.446	0.000	41
16.223	3.234	0.000	14.712	3.087	0.000	0.000	0.446	0.000	42
0.165	0.000	0.000	0.142	0.000	0.000	0.000	0.005	0.000	43
10160.000	0.000	0.000	9624.000	0.000	0.000	0.000	10307.000	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)	144			205		
7	Plant Hours Connected to Load	7492			1729		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	146			232		
10	When Limited by Condenser Water	141			177		
11	Average Number of Employees	31			4		
12	Net Generation, Exclusive of Plant Use - KWh	234884000			58772000		
13	Cost of Plant: Land and Land Rights	22059			1597635		
14	Structures and Improvements	5064160			1650590		
15	Equipment Costs	29408316			22711811		
16	Asset Retirement Costs	2366374			0		
17	Total Cost	36860909			25960036		
18	Cost per KW of Installed Capacity (line 17/5) Including	250.7545			114.4622		
19	Production Expenses: Oper, Supv, & Engr	1893			192500		
20	Fuel	24024250			12350892		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	223617			118672		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	21			0		
26	Misc Steam (or Nuclear) Power Expenses	2067503			351714		
27	Rents	0			0		
28	Allowances	194547			0		
29	Maintenance Supervision and Engineering	59611			903		
30	Maintenance of Structures	61488			-12341		
31	Maintenance of Boiler (or reactor) Plant	149150			0		
32	Maintenance of Electric Plant	108489			188373		
33	Maintenance of Misc Steam (or Nuclear) Plant	1296281			435052		
34	Total Production Expenses	28186850			13625765		
35	Expenses per Net KWh	0.1200			0.2318		
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	287716	954295	0	140013	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	154698	1029	0	138124	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	58.096	7.305	0.000	89.299	0.000	0.000
41	Average Cost of Fuel per Unit Burned	58.886	7.305	0.000	88.040	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	9.063	7.102	0.000	15.176	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.112	0.000	0.000	0.210	0.000	0.000
44	Average BTU per KWh Net Generation	12410.000	0.000	0.000	13820.000	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: *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			1088			178	6
		4019			12044			2359	7
		0			0			0	8
		779			1184			199	9
		643			992			157	10
		20			36			2	11
		204848000			696571000			89526000	12
		2113330			746305			0	13
		9644195			15754336			1471199	14
		144840006			238963580			27752084	15
		0			0			0	16
		156597531			255464221			29223283	17
		181.8322			194.9811			159.1682	18
		1907717			1751525			407647	19
		23814895			76789364			10636682	20
		0			0			0	21
		68674			47096			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		861720			1515564			230092	26
		0			0			0	27
		68			62			0	28
		0			291498			0	29
		55166			0			9887	30
		0			0			0	31
		0			5051			66062	32
		419089			1413404			134783	33
		27127329			81813564			11485153	34
		0.1324			0.1175			0.1283	35
Oil	Gas		Oil	Gas		Oil	Gas		36
BBL	MCF		BBL	MCF		BBL	MCF		37
103205	2195325	0	168125	8062294	0	33447	1074513	0	38
138628	1035	0	138151	1022	0	139143	1032	0	39
89.630	7.130	0.000	92.881	7.671	0.000	93.748	7.442	0.000	40
78.092	7.130	0.000	87.333	7.671	0.000	77.159	7.442	0.000	41
13.412	6.892	0.000	15.051	7.502	0.000	13.203	7.214	0.000	42
0.188	0.000	0.000	0.199	0.000	0.000	0.192	0.000	0.000	43
14020.000	0.000	0.000	13235.000	0.000	0.000	14565.000	0.000	0.000	44

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *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			176
7	Plant Hours Connected to Load			2726			873
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			226			201
10	When Limited by Condenser Water			176			150
11	Average Number of Employees			5			0
12	Net Generation, Exclusive of Plant Use - KWh			83561000			35203000
13	Cost of Plant: Land and Land Rights			0			824781
14	Structures and Improvements			1074388			1328420
15	Equipment Costs			24025994			21437037
16	Asset Retirement Costs			0			586346
17	Total Cost			25100382			24176584
18	Cost per KW of Installed Capacity (line 17/5) Including			112.6588			133.5870
19	Production Expenses: Oper, Supv, & Engr			412718			352735
20	Fuel			11868272			7382097
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			6753			9114
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			261151			191351
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			0			57885
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			58051			0
33	Maintenance of Misc Steam (or Nuclear) Plant			348204			218680
34	Total Production Expenses			12955149			8211862
35	Expenses per Net KWh			0.1550			0.2333
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	75098	839288	0	90421	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	139203	1034	0	138677	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	89.689	6.798	0.000	87.249	0.000	0.000
41	Average Cost of Fuel per Unit Burned	81.505	6.798	0.000	79.504	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	13.941	6.572	0.000	13.650	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.218	0.000	0.000	0.204	0.000	0.000
44	Average BTU per KWh Net Generation	15643.000	0.000	0.000	14960.000	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			122			214	6
		568			2252			6097	7
		0			0			0	8
		70			133			225	9
		50			110			203	10
		0			2			12	11
		11924000			51941000			1019574000	12
		65917			184271			0	13
		405755			791389			10553414	14
		8196090			17054316			69981314	15
		0			0			0	16
		8667762			18029976			80534728	17
		128.2593			117.5127			289.5891	18
		433167			86231			1340109	19
		1522939			6175263			55152912	20
		0			0			0	21
		21197			204179			143586	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		119268			205134			422448	26
		0			0			0	27
		0			0			17	28
		25087			0			0	29
		0			16787			0	30
		0			0			0	31
		0			47609			288707	32
		165073			220217			1168573	33
		2286731			6955420			58516352	34
		0.1918			0.1339			0.0574	35
Oil	Gas		Oil	Gas		Gas			36
BBL	MCF		BBL	MCF		MCF			37
3569	183262	0	210	875515	0	7777287	0	0	38
138594	1033	0	137415	1034	0	1033	0	0	39
100.419	6.660	0.000	0.000	7.043	0.000	7.092	0.000	0.000	40
82.363	6.660	0.000	35.203	7.043	0.000	7.092	0.000	0.000	41
14.149	6.444	0.000	6.099	6.809	0.000	6.865	0.000	0.000	42
0.249	0.000	0.000	0.000	0.119	0.000	0.054	0.000	0.000	43
17621.000	0.000	0.000	0.000	17459.000	0.000	7880.000	0.000	0.000	44

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Rio Pinar* (b)			Plant Name: *Univ. of Florida* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1970			1994		
4	Year Last Unit was Installed	1970			1994		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	19.29			43.00		
6	Net Peak Demand on Plant - MW (60 minutes)	15			46		
7	Plant Hours Connected to Load	43			7817		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	16			47		
10	When Limited by Condenser Water	13			45		
11	Average Number of Employees	0			11		
12	Net Generation, Exclusive of Plant Use - KWh	504000			344781000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	88646			6499783		
15	Equipment Costs	3035059			35028033		
16	Asset Retirement Costs	0			0		
17	Total Cost	3123705			41527816		
18	Cost per KW of Installed Capacity (line 17/5) Including	161.9339			965.7632		
19	Production Expenses: Oper, Supv, & Engr	31626			397121		
20	Fuel	127354			21351714		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5635			1395		
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	5706			66132		
27	Rents	0			0		
28	Allowances	0			6		
29	Maintenance Supervision and Engineering	0			345410		
30	Maintenance of Structures	16506			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			514085		
33	Maintenance of Misc Steam (or Nuclear) Plant	10700			1417985		
34	Total Production Expenses	197527			24093848		
35	Expenses per Net KWh	0.3919			0.0699		
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	1497	0	0	3359634	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138372	0	0	1034	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	92.222	0.000	0.000	6.334	0.000	0.000
41	Average Cost of Fuel per Unit Burned	79.724	0.000	0.000	6.334	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	13.718	0.000	0.000	6.128	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.237	0.000	0.000	0.062	0.000	0.000
44	Average BTU per KWh Net Generation	17262.000	0.000	0.000	10072.000	0.000	0.000

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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
2005			4
1655.75	0.00	0.00	5
1558	0	0	6
20212	0	0	7
0	0	0	8
1660	0	0	9
1456	0	0	10
45	0	0	11
7154180000	0	0	12
13204208	0	0	13
66423546	0	0	14
712975816	0	0	15
0	0	0	16
792603570	0	0	17
478.6976	0.0000	0.0000	18
877721	0	0	19
393517049	0	0	20
0	0	0	21
4370083	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
2305618	0	0	26
0	0	0	27
90	0	0	28
59541	0	0	29
0	0	0	30
0	0	0	31
1643741	0	0	32
5879192	0	0	33
408653035	0	0	34
0.0571	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Oil	Gas								36
BBL	MCF								37
1846	50530634	0	0	0	0	0	0	0	38
133248	1017	0	0	0	0	0	0	0	39
0.000	7.768	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
53.312	7.768	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
9.526	7.638	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.068	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
7185.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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	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	4,287.16	543.02	74

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	12/31/2006	End of 2006/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
2156 KCM ACSR	2,099,487	20,841,657	22,941,144					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	258,670	2,109,689	2,368,359					9
								10
								11
1081 KCM ACSR	85,476	3,479,183	3,564,659					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	521,102	5,723,911	6,245,013					20
1590 KCM ACSR								21
1590 KCM ACSR		635,748	635,748					22
2335 KCM ACAR	1,237,622	1,387,207	2,624,829					23
1590 KCM ACSR	43,803	1,562,869	1,606,672					24
1590 KCM ACSR								25
1590 KCM ACSR								26
1590 KCM ACSR								27
1590 KCM ACSR	133,007	2,839,042	2,972,049					28
1622 KCM		3,429,434	3,429,434					29
1590 KCM ACSR		110,272	110,272					30
1590 KCM ACSR	1,273,186	11,550,515	12,823,701					31
1590 KCM ACSR	775,227	7,013,773	7,789,000					32
954 KCM ACSR	219,431	6,447,801	6,667,232					33
1590 KCM ACSR	442,027	3,438,109	3,880,136					34
1590 KCM ACSR	1,621,137	10,461,338	12,082,475					35
	58,182,739	650,666,309	708,849,048	485,230	7,071,529		7,556,759	36

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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of 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	4,287.16	543.02	74

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TRANSMISSION LINE STATISTICS (Continued)

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8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
1590 KCM ACSR								1
1590 KCM ACSR	1,128,343	7,334,904	8,463,247					2
954 KCM ACSR	1,207,871	4,148,013	5,355,884					3
954 KCM ACSR								4
954 KCM ACSR	626,506	5,362,326	5,988,832					5
954 KCM ACSR								6
954 KCM ACSR								7
1590 KCM ACSR	66,391	139,498	205,889					8
1590 KCM ACSR	284,757	2,228,275	2,513,032					9
1590 KCM ACSR								10
1590 KCM ACSR								11
1590/1431 KCM								12
1590 KCM ACSR	575,819	2,632,897	3,208,716					13
1590 KCM ACSR								14
1590 KCM ACSR								15
954 KCM ACSR	235,351	2,861,821	3,097,172					16
954 KCM ACSR								17
1590 KCM ACSR								18
1431 KCM ACSR								19
1590 KCM ACSR								20
954 KCM ACSR	195,181	1,614,155	1,809,336					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	3,867,981	3,931,904					32
954 KCM ACSR								33
954 KCM ACSR								34
1081 KCM ACAR	55,284	1,943,936	1,999,220					35
	58,182,739	650,666,309	708,849,048	485,230	7,071,529		7,556,759	36

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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	TIGER BAY	TECO	230.00	230.00	CP	0.10		1
3					ST	5.86		
4					WH	1.38		
5	HINES ENERGY	FORT MEADE	230.00	230.00	SP	6.45		1
6	HINES ENERGY	BARCOLA	230.00	230.00	SP	3.09		1
7	HINES ENERGY	BARCOLA (2ND CIRCUIT)	230.00	230.00	SP	3.09		1
8	HINES ENERGY	TIGER BAY	230.00	230.00	SP	0.64	3.51	
9	HINES PLANT	HINES	230.00	230.00	SP	1.64		
10	OLD SUB NORTH	NEW SUB NORTH	230.00	230.00	SP	0.22		1
11	INTERCESSION CITY	LAKE BRYAN 2ND CIRCUIT	230.00	230.00	SP	7.84		1
12	KATHLEEN	WEST LAKELAND	230.00	230.00	WH	14.50		1
13					CP	1.31		
14	KATHLEEN	ZEPHYRHILLS NORTH	230.00	230.00	WH	0.83		1
15					CP	8.70		
16					WP	1.35		
17	LARGO	PASADENA	230.00	230.00	ST		1.61	1
18					SP	13.13		
19	LAKE TARPON	CURLEW	230.00	230.00	ST	4.32		1
20	LAKE TARPON	HIGGINS	230.00	230.00	CP	2.57		1
21					SP	3.02		
22	LAKE TARPON	LARGO	230.00	230.00	SP	14.49		1
23					CP	2.90		
24	LAKE TARPON	SEVEN SPRINGS	230.00	230.00	ST	2.90		1
25	LAKE TARPON	TECO EXIST	230.00	230.00	ST	0.68		1
26					SP	0.81		
27	NORTHEAST	CURLEW	230.00	230.00	ST	16.95	12.78	1
28	NORTHEAST	40TH ST.	230.00	230.00	CP	0.16		1
29					SP	8.16		
30	NORTH LONGWOOD	PIEDMONT	230.00	230.00	SP	0.31	4.04	1
31					WH	6.16		
32	NORTH LONGWOOD	FP&L CO TIE	230.00	230.00	SP	4.04		1
33					WH	2.77		
34	NORTH LONGWOOD	RIO PINAR	230.00	230.00	SP	0.58	3.94	1
35					CP	0.21		
36					TOTAL	4,287.16	543.02	74

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TRANSMISSION LINE STATISTICS (Continued)

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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)	
1081 KCM ACAR								1
1590/1081 KCM	202,353	133,977	336,330					2
1081 KCM ACAR								3
1081/954 KCM								4
954 KCM ACSR		2,805,003	2,805,003					5
954 KCM ACSR		1,531,577	1,531,577					6
954 KCM ACSR		1,412,301	1,412,301					7
954 KCM ACSR		1,455,041	1,455,041					8
954 KCM ACSR		975,065	975,065					9
2335 KCM ACAR		187,074	187,074					10
1622 ACSS TW		5,971,927	5,971,927					11
1590 KCM ACSR	507,363	2,962,410	3,469,773					12
1590 KCM ACSR								13
1590 KCM ACSR	275,097	3,010,806	3,285,903					14
1590 KCM ACSR								15
1590 KCM ACSR								16
1590 KCM ACSR	152,473	3,055,983	3,208,456					17
1590 KCM ACSR								18
1590 KCM ACSR		955,417	955,417					19
1590 KCM ACSR	15,699	1,499,798	1,515,497					20
1590 KCM ACSR								21
1590 KCM ACSR	412,563	8,575,830	8,988,393					22
1590 KCM ACSR								23
1590 KCM ACSR	189,338	694,404	883,742					24
1590 KCM ACSR		197,855	197,855					25
1590 KCM ACSR								26
1590 KCM ACSR	1,524,958	2,482,574	4,007,532					27
1590 KCA ACSR	288,076	1,390,184	1,678,260					28
1081 KCA ACAR								29
954 KCM ACSR	16,834	1,411,376	1,428,210					30
954 KCM ACSR								31
954 KCM ACSR	207,841	1,292,586	1,500,427					32
954 KCM ACSR								33
1590 KCM ACSR	420,736	1,828,798	2,249,534					34
954 KCM ACSR								35
	58,182,739	650,666,309	708,849,048	485,230	7,071,529		7,556,759	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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					AT	10.91		
2	NEWBERRY	WILCOX	230.00	230.00	SP	19.33		1
3	NORTHEAST	PINELLAS	230.00	230.00	CP	1.90		1
4	PIEDMONT	SORRENTO	230.00	230.00	SP	4.24		1
5					CP	6.45		
6					WH	4.79		
7	PIEDMONT	WOODSMERE	230.00	230.00	WH	6.72		1
8	PORT ST. JOE	GULF POWER	230.00	230.00	ST	33.99		1
9	RIO PINAR	OUC TIE	230.00	230.00	SP	0.52		1
10					AT	2.19		
11	SILVER SPRINGS	DELAND WEST	230.00	230.00	SL	39.93		1
12					SH	0.92		
13					SP	1.57		
14	SUWANNEE RIVER PLANT	FORT WHITE	230.00	230.00	ST	38.08		1
15	SKY LAKE	OUC TIE	230.00	230.00	CP	2.40		1
16					WP	2.22		
17	SUWANNEE	PERRY	230.00	230.00	ST	28.61		1
18	SUWANNEE PEAKERS	SUWANNEE	230.00	230.00	WH	0.63		1
19	SUWANNEE	GEORGIA GPC TIE	230.00	230.00	ST	18.36		1
20	TIGER BAY	FORT MEADE 2	230.00	230.00	SP	0.44	1.78	1
21	ULMERTON	LARGO	230.00	230.00	ST	5.05		1
22	VANDOLAH	WHIDDEN	230.00	230.00	SP	14.40		1
23	WINDERMERE	INTERCESSION CITY	230.00	230.00	WH	9.80		1
24					CP	0.27		
25					SP	5.33	4.85	
26	WINDERMERE	WOODSMERE	230.00	230.00	WH	4.68		1
27					ST	1.82		
28	WEST LAKE WALES	INTERCESSION CITY	230.00	230.00	WH	29.34		1
29					SP	0.79		
30	WEST LAKE WALES	FP&L TIE	230.00	230.00	AT	58.48		1
31	WEST LAKE WALES	TECO TIE	230.00	230.00	AT	2.29		1
32	WINDERMERE	OUC TIE	230.00	230.00	WH	1.31		1
33	WOODSMERE	OUC TIE	230.00	230.00	ST		0.92	1
34								
35								
36					TOTAL	4,287.16	543.02	74

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	12/31/2006	End of 2006/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	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)	
954 KCM ACSR								1
1590 KCM ACSR	661,118	5,777,745	6,438,863					2
954 KCM ACSR		4,498	4,498					3
1590 KCM ACSR	574,273	5,147,573	5,721,846					4
1590 KCM ACSR								5
1590 KCM ACSR								6
954 KCM ACSR	15,605	491,284	506,889					7
795 KCM ACSR	71,747	2,336,296	2,408,043					8
954 KCM ACSR	100,034	2,372,735	2,472,769					9
954 KCM ACSR								10
1590 KCM ACSR	54,890	6,782,807	6,837,697					11
1590 KCM ACSR								12
1590 KCM ACSR								13
954 KCM ACSR	199,660	2,362,830	2,562,490					14
954 KCM ACSR	121,530	1,156,873	1,278,403					15
954 KCM ACSR								16
795 KCM ACSR	151,754	1,320,102	1,471,856					17
795 KCM ACSR		8,063	8,063					18
954 KCM ACSR	104,190	1,110,105	1,214,295					19
954 KCM ACSR		747,871	747,871					20
1590 KCM ACSR	601,048	1,724,023	2,325,071					21
1622ACSS TW		14,167,144	14,167,144					22
954 KCM ACSR	135,968	4,786,951	4,922,919					23
954 KCM								24
1622ACSS TW								25
1590 KCM ACSR	19,739	886,234	905,973					26
1590 KCM ACSR								27
954/1081 KCM	364,444	3,225,622	3,590,066					28
1622ACSS TW								29
954 KCM ACSR	595,327	4,760,766	5,356,093					30
954 KCM ACSR	17,342	232,082	249,424					31
954 KCM ACSR		513,322	513,322					32
954 KCM ACSR		4,479	4,479					33
								34
								35
	58,182,739	650,666,309	708,849,048	485,230	7,071,529		7,556,759	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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	OTHER TRANS. LINES	OVERHEAD 115 & 69				2,815.49	304.00	
2	OTHER TRANS. LINES	UNDERGROUND 115				47.29		
3								
4	Total Overhead Transmission	Line Expenses				4,287.16	543.02	74
5		(230, 115, 69 Kv)						
6								
7								
8								
9								
10								
11								
12								
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14								
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30								
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32								
33								
34								
35								
36					TOTAL	4,287.16	543.02	74

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	12/31/2006	End of 2006/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	34,072,689	373,504,759	407,577,448					1
	88,132	12,220,174	12,308,306					2
				485,230	7,071,529		7,556,759	3
	58,182,739	650,666,309	708,849,048	485,230	7,071,529		7,556,759	4
								5
								6
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								34
								35
	58,182,739	650,666,309	708,849,048	485,230	7,071,529		7,556,759	36

Schedule Page: 422.4 Line No.: 34 Column: f

2006 transmission pole mile statistics have been updated to reflect current and prior year minor additions.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Haines City (ICLW-238)	Marley (ICLW-261)	0.09	CP	20.00	1	1
2	FTR 167-1	FTR-189	0.10	SP	17.00	1	1
3	CS-31 SW	Wakulla TEC	0.01	CP	6.00	1	1
4	Atwater	Liberty	16.69	CP	16.00	1	1
5	BW 90-1	BW 90-3	0.02	CP	3.00	1	1
6	Camp Lake	Windermere	23.13	ST	4.00	1	1
7	Intercession City	Lake Bryan	7.84	SP	8.00	1	1
8	Intercession City	Lake Bryan	10.35	CP	8.00	1	1
9	Old Town	Dempsey	6.39	CP	17.00	1	1
10	JS 169-8	JS 169-22.5	1.72	CP	8.00	1	1
11							
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42							
43							
44	TOTAL		66.34		107.00	10	10

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	12/31/2006	End of 2006/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 KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
795	AAC	V	69		2,622,547	927,834	-85,783	3,464,598	1
795	AAC	V	69		168,517	26,041	-18,873	175,685	2
336	ACSR	V	69		32,784	97,152		129,936	3
795	AAC	V	115	16,719,638	21,779,818	4,363,907		42,863,363	4
4/0	ACSR	V	69		19,081	11,785	-4,139	26,727	5
1590	ACSR	V	230		934,628	129,790		1,064,418	6
1622	ACSS TW	V	230		4,215,302	1,756,625		5,971,927	7
954	ACSR	V	69		2,573,953	887,836		3,461,789	8
795	KCM AAC	V	69		112,974	92,160		205,134	9
795	ACSR	V	115		246,878	234,869		481,747	10
									11
									12
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									42
									43
				16,719,638	32,706,482	8,527,999	-108,795	57,845,324	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	12/31/2006	End of 2006/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
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 Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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 Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/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
2	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
13	1					33
25	1					34
40	2					35
13	1					36
60	3					37
20	1					38
30	1					39
9	1	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	12/31/2006	End of 2006/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	DELAND EAST - 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) 12/31/2006	Year/Period of Report End of 2006/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
40	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
90	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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	DELTONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	
2	DELTONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
3	DELTONA EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
4	DOUGLAS AVENUE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	DUNNELLON TOWN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	EAGLENEST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	EATONVILLE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	ECON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
9	EUSTIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	EUSTIS SOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	FERN PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
12	GROVELAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	116.00	
14	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
15	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
16	HOMOSASSA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
17	HOWEY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	INGLIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	67.00	
19	INGLIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	INVERNESS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	7.00
21	INVERNESS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	KELLER ROAD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23	KELLY PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	LADY LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	LAKE ALOMA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	LAKE EMMA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
27	LAKE HELEN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
28	LAKE WEIR - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
29	LEBANON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	12.00	
30	LIBSON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	LOCKHART - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
32	LOCKWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	MAITLAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	MARICAMP - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	MARTIN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	MCINTOSH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
38	MINNEOLA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
39	MONTEVERDE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
40	MOUNT DORA - 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	12/31/2006	End of 2006/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.
75	1					1
120	3					2
60	2					3
60	2					4
40	2					5
19	2					6
90	3					7
100	2					8
60	2					9
63	2					10
30	1					11
19	2					12
250	1					13
250	1					14
19	2					15
20	1					16
13	1	1				17
100	1					18
9	1					19
160	2					20
60	2					21
60	2					22
9	1					23
29	2					24
100	2					25
100	2					26
55	2					27
19	2					28
5	1	1				29
40	2					30
100	2					31
30	1					32
40	2					33
90	3					34
19	2					35
20	1					36
9	1					37
20	1					38
40	2					39
40	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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	MYRTLE LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
2	NORTH LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
3	NORTH LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
4	OCOEE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	OKAHUMPKA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	ORANGE BLOSSOM - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	ORANGE CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	115.00	14.00
8	ORANGE CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
9	OVIEDO - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	PIEDMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
11	PIEDMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
12	PLYMOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	PLYMOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
14	RAINBOW SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
15	REDDICK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	SANTOS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	SILVER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
18	SILVER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	SILVER SPRINGS SHORES-NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	SPRING LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	TROPIC TERRACE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
22	TURNER PLANT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	7.00
23	TURNER PLANT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	TWIN COUNTY RANCH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	110.00	13.00	
25	TWIN COUNTY RANCH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
26	UNIV OF CENTRAL FL - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	UNIV OF CNTL FL NORTH-NORTH CNTL FL REGION	DIST - UNATTENDED	67.00	13.00	
28	UMATILLA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
29	WEIRSDALE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
30	WEKIVA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
31	WELCH ROAD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
32	WEST CHAPMAN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	WILDWOOD CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	WINTER GARDEN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	WINTER GARDEN CITRUS-NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	WINTER GARDEN CITRUS#2-NORTH CENTRAL FL REGION	DIST - UNATTENDED	12.00		
37	WINTER GARDEN CITRUS#2-NORTH CENTRAL FL REGION	DIST - UNATTENDED	12.00		
38	WINTER PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
39	WINTER PARK EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
40	WINTER PARK EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/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.
100	2					1
250	1					2
100	2					3
90	3					4
40	2					5
40	2					6
250	1					7
60	2					8
90	3					9
250	1					10
100	2					11
13	1	1				12
9	1					13
19	2					14
22	2					15
13	1					16
250	1					17
20	1					18
40	2					19
90	3					20
40	2					21
160	2					22
40	2					23
13	1	1				24
9	1					25
60	2					26
60	2					27
40	2					28
19	2					29
100	2					30
100	2					31
60	2					32
25	1					33
60	2					34
9	1	1				35
1	1					36
5	4					37
120	4					38
500	2					39
100	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	12/31/2006	End of 2006/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 SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
2	WINTER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	WOODSMERE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
4	WOODSMERE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	ZELLWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	ZUBER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7					
8	AGRICOLA #4 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
9	ARBUCKLE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
11	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	67.00	12.00
12	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	AVON PARK NORTH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	BABSON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
15	BARNUM CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	BAY HILL - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	BITHLO - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	BOGGY MARSH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	BONNET CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	CABBAGE ISLAND - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	CANOE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	4.00
22	CELEBRATION - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23	CENTRAL PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	CHAMPIONS GATE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
25	CITRUSVILLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	CLEAR SPRINGS EAST - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
27	COLONIAL - SOUTH CENTRAL FL REGION	DIST-UNATTENDED	69.00	13.00	
28	CONWAY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
29	COUNTRY OAKS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
30	CROOKED LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
31	CURRY FORD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
32	CYPRESSWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	DACO - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	DAVENPORT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	DESOTO CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	DINNER LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	DUNDEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
38	EAST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
39	EAST ORANGE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
40	FISHEATING CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	8.00

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2006	Year/Period of Report End of 2006/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
250	1					1
90	3					2
250	1					3
40	2					4
40	2					5
29	2					6
						7
9	1					8
8	1					9
200	1					10
150	1					11
40	2					12
40	2					13
20	1					14
40	2					15
90	3					16
50	2					17
40	2					18
60	2					19
29	2					20
30	1					21
60	2					22
90	3					23
20	1					24
20	1					25
20	1					26
30	1					27
40	2					28
40	2					29
10	1					30
50	1					31
40	2					32
13	1					33
20	1					34
19	2					35
75	2					36
20	1					37
19	2					38
120	3					39
150	1					40

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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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	67.00	13.00	
2	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	8.00
3	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	110.00	14.00
4	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
5	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	FOUR CORNERS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	FROSTPROOF - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	HAINES CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
9	HEMPLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	HOLOPAW - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	25.00	
11	HORSE CREEK #2 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
12	HUNTERS CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	INTERNATIONAL DRIVE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
14	ISLEWORTH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
15	LAKE BRYAN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
16	LAKE BRYAN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	LAKE LUNTZ - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
18	LAKE MARION - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	LAKE OF THE HILLS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	LAKE PLACID - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	LAKE WILSON - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23	LAKEWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	LEISURE LAKES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	LITTLE PAYNE CREEK#1-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
26	LITTLE PAYNE CREEK#2-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
27	MAGNOLIA RANCH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
28	MAGNOLIA RANCH TEMP - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
29	MARLEY ROAD - SOUTH CENTRAL FL REGION	DIST- UNATTENDED	69.00	13.00	
30	MEADOWS WOODS SOUTH-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
31	MEADOWS WOODS SOUTH-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
32	MIDWAY TEMP - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
33	MULBERRY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	4.00	
34	NARCOOSEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	NORALYN #1 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	12.00	
36	NORALYN #2 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
37	ODESSA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
38	ORANGEWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
39	PARKWAY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
40	PEMBROKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	12.00	

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	12/31/2006	End of 2006/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
9	1					1
60	1					2
150	1					3
200	1					4
9	1					5
60	2					6
50	2					7
80	2					8
60	2					9
25	2					10
9	1					11
60	2					12
100	2					13
19	2					14
500	2					15
90	3					16
30	1					17
20	1					18
20	1					19
40	2					20
60	2					21
40	2					22
55	2					23
9	1					24
13	1					25
13	1					26
13	1	1				27
20	1					28
30	1					29
200	1					30
60	2					31
9	1					32
6	1	1				33
90	3					34
9	3	1				35
9	1	1				36
30	1					37
100	2					38
60	3					39
2	1	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	12/31/2006	End of 2006/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	PINECASTLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
2	POINCIANA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	REEDY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	RIO PINAR - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
5	RIO PINAR - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	SAND LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	SAND MOUNTAIN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	SEBRING EAST - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
9	SHINGLE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	SKY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
11	SKY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
12	SOUTH BARTOW - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	SOUTH FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	25.00	
14	SOUTH FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	4.00	
15	SUNFLOWER - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
16	SUN'N LAKES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	TAFT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	TAUNTON RD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	VINELAND - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	WAUCHULA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	WEST DAVENPORT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
22	WEST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
23	WEST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	WESTRIDGE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	WEWAHOOTEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	13.00	4.00	
26	WEWAHOOTEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	WHIDDEN CREEK #1 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
28	WINDERMERE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
29	WINDERMERE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
30					
31	TOTAL DISTRIBUTION		34899.00	7595.00	360.00
32					
33	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
34	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
35	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	133.00	
36	BROOKSVILLE WEST - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
37	HIGGINS PLANT - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
38	HUDSON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
39	LAKE TARPON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
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	12/31/2006	End of 2006/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
40	2					3
500	2					4
100	2					5
80	2					6
9	1	1				7
20	1					8
60	2					9
250	1					10
90	3					11
9	1					12
19	1					13
45	2					14
30	1					15
40	2					16
60	2					17
20	1					18
60	2					19
19	2					20
19	2					21
250	1					22
13	1	1				23
20	1					24
9	1	1				25
13	1	1				26
20	1					27
200	1					28
40	2					29
						30
24840	574	51				31
						32
750	1					33
250	1					34
250	1					35
250	1					36
250	1					37
500	2					38
1500	2	1				39
						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	12/31/2006	End of 2006/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	DRIFTON - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	5.00
2	GUMBAY - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
3	HAVANA - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
4	IDYLWILD - NORTH FLORIDA REGION	TRANS - UNATTENDED	138.00	67.00	12.00
5	QUINCY - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	4.00
6	SUWANNEE 230 KV - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
7	TALLAHASSEE - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	8.00
8	WILCOX - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
9	ANDERSEN - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	14.00
10	BARBERVILLE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	115.00	66.00	33.00
11	CAMP LAKE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	15.00
12	CENTRAL FLORIDA - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	512.00	230.00	14.00
13	CENTRAL FLORIDA - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
14	CLERMONT EAST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	14.00
15	CRYSTAL RIVER EAST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	116.00	
16	DELAND WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
17	DELAND WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	115.00	67.00	15.00
18	HAINES CREEK - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
19	MARTIN WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
20	ROSS PRAIRIE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	69.00	
21	SORRENTO - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
22					
23	AVALON - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	69.00	
24	BARCOLA - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
25	GRIFFIN - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	115.00	13.00
26	INTERCESSION CITY - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
27	KATHLEEN - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	512.00	230.00	14.00
28	NORTH BARTOW - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
29	VANDOLAH - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	23.00
30					
31	TOTAL TRANSMISSION		8396.00	3411.00	240.00
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) 12/31/2006	Year/Period of Report End of 2006/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.
105	2					1
75	1					2
75	1					3
150	1					4
75	1					5
400	2					6
120	2					7
150	1					8
133	1					9
30	4	1				10
150	1					11
1500	2					12
450	2					13
250	1					14
250	1					15
200	1					16
125	1					17
250	1					18
200	1					19
150	1					20
250	1					21
						22
250	1					23
150	1					24
250	1					25
250	1					26
750	1					27
150	1					28
400	2					29
						30
11038	46	2				31
						32
						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, 2006

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, 2006 to December 31, 2006, 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.

4-24-07

Date

Will A. Garrett

Signature

Will A. Garrett

Name

Controller - Progress Energy Florida

Title

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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
Fred N. Day IV	President & Chief Executive Officer Progress Energy Carolinas	Director	Advanced Energy Corporation Raleigh, NC
		Director	NC State Engineering Foundation Raleigh, NC
		Director	Triangle Tomorrow Research Triangle Park, NC
		Director	Greater Raleigh Chamber of Commerce Raleigh, NC
		Director	NC Military Foundation
		President	AEIC Board of Directors Birmingham, AL
		President	Southeastern Electric Exchange Atlanta, GA
		Director / Exec VP	Florida Power Corporation
		Director	Microcell Raleigh, NC
		Director	N.C. Economic Development Board and Executive Committee Raleigh, NC
		Director / VP	Progress Energy Foundation Raleigh, NC
Will A. Garrett	Controller	None	
H. Willliam Habermeyer, Jr.	Director, President and CEO	Board Member	Enterprise Florida Orlando, FL
		Board Member & Chair	Pinellas County Education Foundation Largo, FL
		Board Member	Florida Chamber of Commerce Tallahassee, FL

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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
H. Willliam Habermeyer, Jr.		Board Member	Tampa Bay Partnership Tampa, FL
		Board Member	Eckerd College St. Petersburg, FL
		Board Member	USF St. Petersburg Campus St. Petersburg, FL
		Trustee & Vice President	Salvador Dali Museum St. Petersburg, FL
		Board Member	Boys and Girls Club of the Suncoast St. Petersburg, FL
		Board Member	Museum of Fine Arts St. Petersburg, FL
		Director	Raymond James Financial, Inc St. Petersburg. FL
C.S. Hinnant	Senior Vice President & Chief Nuclear Officer	Director	Carolinas Virginia Nuclear Power Associates, Inc. Columbia, SC
William D. Johnson	Director, Group President Energy Delivery	Board Member	Golden LEAF Raleigh, NC
		Board Member	Daugherty Endowment Fund Raleigh, NC
		Board Chair	Exploris Raleigh, NC
		Board Member	Frankie Lemmon Foundation Raleigh, NC
		Board Member	Rex Hospital Raleigh, NC
		Board of Visitors	Carolina Environmental Program

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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
		Board Member	Caronet, Inc.
		Board Member	INPO National Nuclear Accrediting Board Atlanta, GA
		Chair	NC Museum of Natural Sciences, Private Sector Campaign Committee for the Nature Research Center
		Board Member	Progress Capital Holdings, Inc.
		Board Member	Progress Energy Foundation
		Board Member	Progress Energy Service Company
		Board Member	Progress Energy Ventures, Inc.
		Board Member	Progress Fuels Corporation
		Board Member	Progress Telecommunications Corporation
Jeff Lyash	President	Director	Enterprise Florida, Inc. Orlando, FL
		Trustees	Florida Chamber of Commerce Foundation, Inc. Tallahassee, FL
		Executive Committee	Florida Electric Power Coordinating Group (FCG) Tampa, FL
		Council Member	Florida High Tech Corridor
		Directors	Florida Reliability Coordinating Council (FRCC) Tampa, FL

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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
Jeff Lyash	President	Directors	Pinellas Education Foundation Largo, FL
		Directors	Tampa Bay Partnership Tampa, FL
		Member	The Florida Council of 100 Tampa, FL
		Director, Member, Chair	The Florida Orchestra Tampa, FL
John R. McArthur	Director, Senior Vice President	Board of Directors	Florida Power Corporation
		Chairman	N.C. Education Lottery Commission Raleigh, NC
		Board of Directors	Global Transpark Foundation, Inc. Kinston, NC
		Board of Directors	Business - Industry Political Action Committee (BIPAC) Raleigh, NC
		Board of Directors	Florida Progress Corporation
		Board of Directors	Progress Capital Holdings, Inc.
		Board of Directors	Carolina Power & Light Company, DBA Progress Energy Carolinas, Inc.
		Board of Directors	Progress Energy Foundation, Inc.
		Board of Directors	Progress Energy Service Company, LLC
		Board of Directors	Progress Energy, Inc.

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Name and Address
		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
Robert B. McGehee	Chairman and CEO	Board Member	WANO, Atlanta Center Atlanta, GA
		Board Member	INPO Atlanta, GA
		Board Member	NEI Washington, D.C.
		Board Member	EEI Washington, D.C.
		Board Member	U.S. Chamber of Commerce Washington, D.C.
		Chairman/Director	Carolina Power & Light Company, DBA Progress Energy Carolinas, Inc.
		Chairman/Director	Florida Power Corporation, DBA Progress Energy Florida, Inc.

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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
Robert B. McGehee	Chairman and CEO	Chairman/Director CEO President	Florida Progress Corporation
		Director	PV Holdings, Inc.
		Chairman/Director	Progress Capital Holdings, Inc.
		Director and President	Progress Energy Foundation, Inc.
		Manager	Progress Energy Service Company, LLC
		Executive Committee	Progress Energy, Inc.
		Director/Chairman	Progress Energy Ventures, Inc.
		Director/Chairman	Progress Fuels Corporation
		Director/Chairman	Progress Real Estate Holdings, Inc.
		Vice Chairman	Atomic Energy Committee of the Public Utility Communications and Transportation Law Section of the American Bar Association
		Board Member	The Florida Council of 100 Tampa, FL
Frank A. Schiller	General Counsel	Corporate Secretary General Counsel	Black Hawk Synfuel, LLC.
		Director	Capitan Corporation
		Director	Carofund, Inc.

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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
		Corporate Secretary General Counsel	CaroHome, LLC
		Assistant Secretary General Counsel	Carolina Power & Light
		Corporate Secretary General Counsel	Ceredo Liquid Terminal, LLC
		Corporate Secretary General Counsel	Ceredo Synfuel, LLC
		Corporate Secretary General Counsel	Colona Newco, LLC
		Corporate Secretary General Counsel	Colona Sub No. 2, LLC
		Director	Dulcimer Land Company, Inc.
		Corporate Secretary General Counsel	EFC Synfuel, LLC
		Corporate Secretary General Counsel	Effingham County Power, LLC
		Corporate Secretary General Counsel	Florida Power Corporation
		Director	Florida Progress Funding Corporation
		Director	Kanawha River Terminals, Inc.
		Director	Kentucky May Coal Company, Inc.
		Director	Marigold Dock, Inc.

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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	Secretary General Counsel	Marmet Synfuel, LLC
		Secretary General Counsel	MPC Generating, LLC
		Director	PEC Fort Drum, Inc.
		Secretary	PFC Property Holdings, Inc.
		Secretary	PFC Receivables, Inc.
		Director	PIH Tax Credit Fund, III. IV, V
		Director	PIH, Inc.
		Director	Powell Mountain Coal Company, Inc.
		Vice President Corporate Secretary General Counsel	Progress Capital Holdings, Inc.
		Director	Progress Energy Envirotree, Inc.
		Vice President Corporate Secretary General Counsel	Progress Energy Service Company, LLC
		Corporate Secretary	Progress Fuels Corporation
		Corporate Secretary General Counsel	Progress Genco Ventures, LLC
		Director	Progress Materials, Inc.

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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	Progress Provisional Holdings, Inc.
		Secretary General Counsel	Progress Real Estate Holdings, Ltd.
		Director	Progress Reinsurance Company, Ltd.
		Director	Progress Synfuel Holdings, Inc.
		Director	Progress Telecommunications
		Corportate Secretary General Counsel	Progress Ventures, Inc.
		Corportate Secretary General Counsel	PV Holdings, Inc.
		Corportate Secretary General Counsel	PV Synfuels, LLC.
		Corportate Secretary General Counsel	Riverside Synfuel, LLC
		Corportate Secretary General Counsel	Sandy River Synfuel, LLC
		Corportate Secretary General Counsel	Solid Energy, LLC
		Corportate Secretary General Counsel	Solid Fuel, LLC
		Director	Stratetic Resource Solutions, Inc.
		Corportate Secretary General Counsel	Washington County Power, LLC
		Director	West Drum Holdings Corporation

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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
Peter M. Scott III	Director, Executive Vice President, Chief Financial Officer	Board of Governors	Capital City Club Raleigh, NC
		Director/President	Capitan Corporation
		Director/President	Carofund, Inc.
		Board Member	North Carolina Museum of Art Foundation Board Raleigh, NC
		Board Member	Nuclear Electric Insurance Limited (NEIL) Wilimington, DE
		Director/President	Progress Capital Holdings, Inc.
		Director/Treasurer	Progress Energy Foundation, Inc.
		CFO	Progress Energy Service Company, LLC
		Director	Progress Fuels Corporation
		Vice President Director	Progress Real Estate Holdings, Inc.
		Director	Progress Ventures, Inc.
		CFO	Florida Power Corporation
		Director	Progress Ventures Holdings, Inc.
		Board Member	RTI International Raleigh, NC
		Board Member	Eckerd Youth Alternatives St. Petersburg, FL
Jeffrey M. Stone	Chief Accounting Officer	None	
Thomas R. Sullivan	Vice President, Treasurer	None	
E. Michael Williams	Senior Vice President	Board of Directors	CISW (Communities in Schools of Wake County) Raleigh, NC

Business Contracts with Officers, Directors and Affiliates

Company: ***Progress Energy Florida Inc.***
For the Year Ended December 31, 2006

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
H. William Habermeyer, Jr. Jeff Lyash	Tampa Bay Partnership, Inc. Tampa, FL	15,000	Donation
H. William Habermeyer, Jr.	Salvador Dali Museum St. Petersburg, Florida	5,000	Donation
H. William Habermeyer, Jr.	Boys & Girls Club of the Suncoast St. Petersburg, Florida	21,000	Donation
H. William Habermeyer, Jr. Jeff Lyash	Florida Chamber of Commerce Tallahassee, Florida	40,000	Dues
H. William Habermeyer, Jr. Jeff Lyash	Pinellas County Education Foundation Largo, Florida	27,500	Donation
H. William Habermeyer, Jr.	University of South Florida Foundation St. Petersburg, Florida	5,000	Donation
Jeff Lyash	The Florida Orchestra Tampa, Florida	21,500	Donation
Jeff Lyash	Florida Reliability Coordinating Group Tampa, Florida	733,500	Dues

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

Company: *Progress Energy Florida Inc.*

For the Year Ended December 31, 2006

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).

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
Line No.	Description	Gross Operating Revenues per Page 300	Interstate and Sales for Resale Adjustments	Adjusted Intrastate Gross Operating Revenues	Gross Operating Revenues per RAF Return	Interstate and Sales for Resale Adjustments	Adjusted Intrastate Gross Operating Revenues	Difference (d) - (g)	
1	Total Sales to Ultimate Customers (440-446, 448)	$ 4,159,030,112	$ 37,538,524	$ 4,121,491,588	$ 4,159,030,112	$ 37,538,524	$ 4,121,491,588	$ -	
2	Sales for Resale (447)	321,091,934	321,091,934	-	321,091,934		-	-	
3	Total Sales of Electricity	4,480,122,046	358,630,457	4,121,491,588	4,480,122,046	37,538,524	4,121,491,588	-	
4	Provision for Rate Refunds (449.1)	(898,573)	(1,869,158)	970,585	(898,573)	(1,869,158)	970,585	-	
5	Total Net Sales of Electricity	4,479,223,473	356,761,300	4,122,462,173	4,479,223,473	35,669,366	4,122,462,173	-	
6	Total Other Operating Revenues (450-456)	80,683,255	39,326,906	41,356,349	79,320,653	39,326,906	39,993,747	1,362,601	(1)
7	Other (Specify)								
8									
9									
10	**Total Gross Operating Revenues**	$ 4,559,906,728	$ 396,088,206	$ 4,163,818,522	$ 4,558,544,126	$ 74,996,272	$ 4,162,455,921	$ 1,362,601	

Notes: '(1) Difference reflects intercompany revenues that are not considered part of operating revenues derived from intrastate business.

Analysis of Diversification Activity
Changes in Corporate Structure

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2006

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)
1/1/2006	West Generating Company, LLC was dissolved.
10/22/04	Pantellos Corp. changed its name to Perfect Commerce, Inc. (Retroactive to 10/22/04).
1/24/2006	PT Holding Company, LLC was formed by the members of Progress Telecom, LLC.
2/16/2006	PT Attachment Solutions, LLC was formed as a wholly-owned subsidiary of PT Holding Company, LLC.
2/16/2006	PT Tower Solutions, LLC was formed as a wholly-owned subsidiary of PT Holding Company, LLC.
2/24/2006	PEC made an additional investment in MircoCell thereby increasing its total investment to 1.417%.
3/1/2006	Dixie Fuels, Ltd. Was sold by Progress Fuels Corporation.
3/14/2006	New Broad River, LLC was formed. PEC Broad River, LLC. owns 50% of the membership interest. The other 50% interest is owned by a third party (CIT).
3/15/2006	PEC Broad River, LLC (NC LLC) was formed as a wholly-owned subsidiary of PEC.
3/20/2006	Progress Telecom, LLC. and its wholly-owned subsidiary, PTLLC Acquisition Co., LLC., were sold to a third party.
3/16/06	Progress Energy's ownership percentage was decreased to 11.11% due to the addition of a new member in NuStart. (Retroactive to 3/16/06).
3/31/06	Florida Progress Corporation sold its interest in the Tampa Bay Devil Rays, Ltd. (Retroactive to 3/31/06).
5/1/2006	Kentucky May Coal Company, a subsidiary of Progress Fuels Corporation, sold Diamond May Coal Company.
5/1/2006	Progress Fuels Corporation sold Progress Land Company.
5/31/2006	DeSoto County Generating Co., LLC was sold to a third party.

Analysis of Diversification Activity
Changes in Corporate Structure
Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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)
6/12/2006	GridFlorida, LLC. was dissolved.
8/31/2006	Rowan County Power, LLC was sold to a third party.
9/18/2006	East Coast Oil Company, LLC. was formed as a single-member LLC under Progress Fuels Corp.
9/22/2006	Vaughan Holding Company, LLC., converted 3.4% of its GP interest in Winchester Production Company ("WPC") to an LP interest. Effective 9/26/06, Vaughan Holding contributed this 3.4% LP interest in WPC to a newly-created legal entity (formed 9/25/06) named Vaughan DE, LLC. (Vaughan DE); Vaughan DE is a single-member LLC under Vaughan Holding.
10/2/2006	Winchester Energy Company, Ltd. and its subsidiaries were sold to EXCO Resources, Inc.
12/31/2006	WGC Holdco, LLC; PFC Gas Holdings, LLC; and East Coast Oil company, LLC were dissolved.

Analysis of Diversification Activity
New or Amended Contracts with Affiliated Companies

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2006

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 Fuels Corporation (PFC)	Bill of Sale whereby Progress Fuels Corporation and Progress Energy Florida, Inc. for the sale of 713 used railcars, one (1) used railcar caboose and one (1) used model switching locomotive. Effective date: January 1, 2006 Price: $ 9,405,513.96

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

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2006

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 Employee benefits, Legal, IT, Acctg Svcs, Telecom, HR, Corp Comm, Risk Mgmt, Environmental Svcs, Corp Mgmt, Shared Corporate Svcs.	$ 154,199,116
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Recurring gas purchases, Mgmt & IT services, Fuel procurement, Mgmt services, Customer Service support	34,096,212
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Non-recurring sale of two GSU transformers	1,551,000
Progress Fuels Corporation	Non-recurring sale of railcars, locomotive and caboose[1]	9,405,514
Progress Fuels Corporation	Non-recurring sale of in-transit coal inventory.[2]	29,960,402
Dixie Fuels, Ltd	Coal transportation charges	2,398,729

[1] See Page 455.

[2] Contract reported on prior year report page 455. Agreement date 12/12/05, effective date 1/1/06.

Analysis of Diversification Activity
Summary of Affiliated Transfers and Cost Allocations

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2006

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	Utility Service Agreement 1/1/2001	S	1460001	7,685,207
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Shared utilty functions, technical services support, generation expansion, CT operations/maintenance; Transmission & Distribution support, oversight, metering, community relations; Customer Service performance solutions, customer service management; Nuclear regulatory, management, assessment, oversight, fuel administration, engineering materials and controls, security, contract support, IT analytical services; Power Operations gas and oil supply, core environmental services, management and finance, planning and work management; Regulated commercial operations power trading, purchased power contract support, joint owner contract support, operational support, gas & oil procurement, wholesale term contract support; Energy Delivery management & oversight; Unregulated customer services, transmission & distribution engineering/design/construction; Engineering; Coal procurement and transportation; Shared utility regulated lighting, exterior lighting, fuel forecasting.	Utility Service Agreement 1/1/2001	P	2340001	35,647,212
Progress Energy Ventures	Energy Trading Mgmt, Technical Support Svcs, Core Env Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460020	540,750
Rowan County Power, LLC[3]	Technical Support Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460024	3,033
Effingham County Power, LLC	Technical Support Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460025	12,562
DeSoto County Generating Company LLC[4]	Technical Support Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460026	292
DeSoto County Generating Company LLC[4]	Equipment repairs	Utility Service Agreement 11/1/2002	S	1433110	2,930
MPC Generating, LLC	Technical Support Svcs	Utility Service Agreement 11/1/2002	S	1460032	675

Analysis of Diversification Activity
Summary of Affiliated Transfers and Cost Allocations

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2006

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)
Walton County Power, LLC	Technical Support Svcs	Utility Service Agreement 11/1/2002	S	1460033	999
Washington County Power, LLC	CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460034	6,496
Progress Fuels Corporation	Aardelite sales, Fly Ash sales, Potable & Process Water sales	Ash Management Contract Extensions 9/1/1995 and 9/2/2005	S	1460061	805,749
Progress Fuels Corporation	In-transit coal[1]	Coal Inventory Purchase Agreement, effective 1/1/2006	P	2340061	29,960,402
Progress Fuels Corporation	Railcars, locomotive and caboose[2]	Bill of Sale - 1/1/2006	P	1071000	9,405,514
Progress Telecommunications	Non recurring fiber indemnification	Utility Service Agreement 1/1/2001	S	1460062	5,409,226
Progress Telecom LLC[5]	Network Services, Land/Pole IRU, Revenue Sharing	IRU and Master Service and Wireless Attachment Agreements - 12/19/2003	S	1460067	316,688
PT Holding Company LLC[6]	Network Services, Land/Pole IRU, Revenue Sharing	Master Service and Wireless Attachment Agreements - 12/19/2003	S	1460071	2,128,968
Dixie Fuels Ltd[7]	Coal transportation charges		P	2320601	2,398,729
Progress Energy Service Company LLC	Labor and associated expenses, materials	Utility Service Agreement 1/1/2001	S	1460098	7,254,688
Progress Energy Service Company LLC	Legal, IT, Acctg Svcs, Telecom, Public Affairs, HR, Corp Comm, Tax Svcs, Risk Mgmt, Environmental Svcs, Corp Mgmt, Treasury, Risk Mgmt, Disbursement Svcs, Other Shared Corp Svcs. Excludes convenience payments and pay agent transactions	Utility Service Agreement 12/1/2000	P	2340098	154,199,116

1 See Page 456.
2 See Pages 455 and 456.
3 Rowan County Power, LLC was sold to an unaffiliated third party on 8/31/2006.
4 DeSoto County Generating Company, LLC was sold to an unaffiliated third party on 5/31/2006.
5 Progress Telecom, LLC was sold to an an unaffiliated third party on 3/20/06.
6 PT Holding Company, LLC was formed 1/24/06 by members of Progress Telecom, LLC.
7 Dixie Fuels, Ltd was sold on an unaffiliated third party on 3/1/06.

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

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2006

Provide a summary of affiliated transactions involving asset transfers or the right to use assets.

Name of Affiliate	Description of Asset or Right	Cost/Orig. Cost	Accumulated Depreciation	Net Book Value	Fair Market Value	Purchase Price	Title Passed Yes/No
Purchases from Affiliates:							
Progress Fuels Corporation	Railcars & Model Switching Locomotive	$ 37,025,538	27,620,027	$ 9,405,514		$ 9,405,514	Yes
Total		**$ 37,025,538**	**-**	**$ 9,405,514**	**$ -**	**$ 9,405,514**	
Sales to Affiliates:		$	$	$	$	**Sales Price**	
None							
Total						$	

Analysis of Diversification Activity
Employee Transfers

Company: Progress Energy Florida, Inc.

For the Year Ended December 31, 2006

List employees earning more than $30,000 annually transferred to/from the utility to/from an affiliate company.

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
PEF	CPL	Sr Nuc Tech Proj Mgmt Spec	Assessor-RNAS	Permanent
PEF	SVC	Sr Customer Service Agent-FL	Assoc Accountant	Permanent
PEF	CPL	Assoc Engr	Assoc Engr	Permanent
PEF	CPL	Supv-Customer Service	Cust Service Agent I	Permanent
PEF	CPL	Customer Service Agent I-FL	Cust Service Agent I	Permanent
PEF	CPL	Engr Tech II	Engr Tech II	Permanent
PEF	CPL	General Mgr-Ops-South-FGD	Gen Mgr-West-FGD	Permanent
PEF	SVC	Customer Service Agent I-FL	IT Trainee-IT&T	Permanent
PEF	SVC	Customer Service Agent I-FL	IT Trainee-IT&T	Permanent
PEF	CPL	Turbine Cert Weld Mech-SM	Mech 1/C	Permanent
PEF	CPL	Supv-Trans Substation Maint	Mgr-Performance Support-ED	Permanent
PEF	CPL	Plt Mgr-Bartow	Plant Mgr-Sutton	Permanent
PEF	SVC	Program Support Asst II-FL	Program Support Asst II-FL	Permanent
PEF	SVC	Sr Energy Efficiency Spec-EDG	Public Policy Analyst-CRAS	Permanent
PEF	SVC	Sr Environmental Specialist	Sr Auditor	Permanent
PEF	CPL	Sr Craft/Technical Trainer	Sr Craft/Technical Trainer	Permanent
PEF	CPL	Sr Eny Del Tech Proj Mgmt Spec	Sr Engr	Permanent
PEF	SVC	Customer Service Trainer-CSC	Sr HR Support Assistant-FL	Permanent
PEF	SVC	Supv-Distribution Field	Sr Occ Health & Safety Spec	Permanent
PEF	SVC	Telecomm Tech (S)	Sr Telecom Anlyst	Permanent
PEF	CPL	Sr Work Mgmt Spec	Sr Work Mgmt Spec	Permanent
PEF	CPL	Shift Supv-FGD	Supt-Maintenance-FGD	Permanent
PEF	CPL	Shift Supv-FGD	Supt-Operations & Results-FGD	Permanent
PEF	CPL	Lead Engr	Supv-Equipment Perf	Permanent
PEF	SVC	Supv-Property Mgmt-FL	Supv-Projects Business Units	Permanent
PEF	SVC	Supv-Materials-South-FGD	Supv-Purchasing	Permanent
PEF	CPL	Region Service Coordinator-ED	Tech T&D Design Spec-ED	Permanent
PEF	SVC	Supv-Dist Tech Svcs	Lead Telecom Anlyst	Permanent
SVC	PEF	Admin Assistant I	Administrative Assistant I-FL	Permanent
SVC	PEF	Administrative Assistant I-FL	Operations Support Asst-FL	Permanent
SVC	PEF	Administrative Assistant I-FL	Administrative Assistant I-FL	Permanent
SVC	PEF	Administrative Assistant II-FL	Administrative Assistant I-FL	Permanent
CPL	PEF	Assessor-RNAS	Assessor-RNAS	Permanent
CPL	PEF	Assoc Bus Fin Anlyst	Plant Services Assistant I-FL	Permanent
CPL	PEF	Aux Oper B-Nuc	Asst Nucl Auxiliary Oper	Permanent
CPL	PEF	Bus Fin Anlyst	Bus Fin Anlyst	Permanent
CPL	PEF	Co-Op-Student 4-Yr Tech	Co-Op-Student 4-Yr Tech	Permanent
EFC	PEF	Control Room Oper III-PFC	Laborer (A)-Production	Permanent
SVC	PEF	Data Management Asst I-FL	Environmental Specialist	Permanent
SVC	PEF	Data Management Asst I-FL	Data Management Asst I-FL	Permanent
CPL	PEF	Dist Info Systems Operator	Assoc Engr Technical Supt Spec	Permanent
CPL	PEF	Engr	Engr	Permanent
SVC	PEF	Environmental Specialist	Environmental Specialist	Permanent

Analysis of Diversification Activity
Employee Transfers

Company: Progress Energy Florida, Inc.
For the Year Ended December 31, 2006

List employees earning more than $30,000 annually transferred to/from the utility to/from an affiliate company.

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
SVC	PEF	Environmental Specialist	Environmental Specialist	Permanent
SVC	PEF	Environmental Specialist	Environmental Specialist	Permanent
SVC	PEF	Environmental Specialist	Environmental Specialist	Permanent
SVC	PEF	Environmental Specialist	Environmental Specialist	Permanent
SVC	PEF	HR Support Assistant I-FL	Admin Asst to Depart Head-FL	Permanent
SVC	PEF	Lead Occ Health & Safety Spec	Lead Occ Health & Safety Spec	Permanent
SVC	PEF	Logistics Planning Anlyst	Logistics Planning Anlyst	Permanent
SVC	PEF	Mgr-Env Ener Sup & CCO-FL	Mgr-Env Ener Sup & CCO-FL	Permanent
SVC	PEF	Mgr-Fleet Maintenance	Mgr-Fleet Maintenance	Permanent
SVC	PEF	Mgr-Materials & Services	Mgr-Materials & Services	Permanent
SVC	PEF	Mgr-PGN FL Health & Safety	Mgr-PGN FL Health & Safety	Permanent
CPL	PEF	Plt Mgr-CT-Asheville	Plt Mgr-CT-Central	Permanent
PVI	PEF	Plt Mgr-CT-Effingham	Plt Mgr-CT-Bartow	Permanent
PVI	PEF	Plt Mgr-Georgia Peakers-CT	Mgr-Maintenance-CT	Permanent
SVC	PEF	Procurement Asst I-FL	Sr Operations Support Asst-FL	Permanent
SVC	PEF	Site Occup Health Nurse-OH+S	Site Occup Health Nurse-OH+S	Permanent
SVC	PEF	Sr Administrative Assistant-FL	Sr Administrative Assistant-FL	Permanent
CPL	PEF	Sr Bus Fin Anlyst	Supv-FGD/CTOD Bus Svcs	Permanent
CPL	PEF	Sr Bus Fin Anlyst	Sr Bus Fin Anlyst	Permanent
CPL	PEF	Sr Bus Fin Anlyst	Sr Bus Fin Anlyst	Permanent
PVI	PEF	Sr Comb Turbine Tech	Comb Turbine Technician	Permanent
CPL	PEF	Sr Engr	Sr Engr	Permanent
CPL	PEF	Sr Engr Technical Supt Spec	Lead Engr Technical Supt Spec	Permanent
CPL	PEF	Sr Engr Technical Supt Spec	Supv-Distribution Field	Permanent
SVC	PEF	Sr Engr Technical Supt Spec	Sr Engr Technical Supt Spec	Permanent
SVC	PEF	Sr Engr Technical Supt Spec	Sr Engr Technical Supt Spec	Permanent
SVC	PEF	Sr Engr Technical Supt Spec	Sr Engr Technical Supt Spec	Permanent
SVC	PEF	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
SVC	PEF	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
SVC	PEF	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
SVC	PEF	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
SVC	PEF	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
SVC	PEF	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
SVC	PEF	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
SVC	PEF	Sr Environmental Specialist	Sr Enrgy Mgmt Sys Supp Spec	Permanent
SVC	PEF	Sr Fleet Svs Spec	Sr Fleet Svs Spec	Permanent
SVC	PEF	Sr Occ Health & Safety Spec	Supv-Distribution Field	Permanent
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent

Analysis of Diversification Activity
Employee Transfers

Company: Progress Energy Florida, Inc.

For the Year Ended December 31, 2006

List employees earning more than $30,000 annually transferred to/from the utility to/from an affiliate company.

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
SVC	PEF	Supv-Mail Services	Supv-Property Mgmt-FL	Permanent
CPL	PEF	VP-Distribution	Sr VP-Energy Delivery-FL	Permanent
SVC	PEF	Lead Telecom Anlyst	Supv-Dist Tech Svcs	Permanent
CPL	PEF	Lead ED Project Analyst	Lead ED Project Analyst	Permanent
CPL	PEF	Lead Engr	Supv-System Integrity	Permanent
CPL	PEF	Lead EngyDel TechProjMgmtSpec	Lead EngyDel TechProjMgmtSpec	Permanent
SVC	PEF	Lead Environmental Specialist	Lead Environmental Specialist	Permanent
SVC	PEF	Lead Environmental Specialist	Lead Environmental Specialist	Permanent

Analysis of Diversification Activity
Non-Tariffed Services and Products Provided by the Utility

Company: Florida Power Corporation

For the Year Ended December 31, 2006

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
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
Wireless Transmission Tower Attachments	4210708	Non-Regulated

Nonutility Property (Account 121)

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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 91) 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)	2,752,511	(1,116,307)	1,636,204
Equipment - Meters System (Florida) (2)	4,925,811	497,738	5,423,549
Equipment - Walk of Fame, St. Pete, FL	1,380,193		1,380,193
Other	389,187	(63,359)	325,828
Generators on Customer premises	732,987		732,987
Communication Equipment (3)	8,411,135	(8,411,135)	0
(1) Land sale for proceeds of 2,464,000 in Jan 2006			
(2) Addition of meter treaters			
(3) Communication 7 year property fully amortized			
Totals	$ 19,431,391	$ (9,093,063)	$ 10,338,328

Number of Electric Department Employees

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2006

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)	**10/29/2006**
2. Total Regular Full-Time Employees	**3894**
3. Total Part-Time and Temporary Employees	**168**
4. Total Employees	**4062**

Details

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Company: Florida Power Corporation
For the Year Ended December 31, 2006

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
(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	335,950.17
Cultural & Arts Organizations	786,465.36
Economic Development	532,725.45
Education Related Contributions	3,009,496.73
Environment	106,699.71
Health & Human Services Contributions	465,961.80
Other	307,687.93
Subtotal Accounts 4261014, 426180T, 4261BUD	5,544,987.15
Investment in Company Owned Life Insurance	(2,437,454.26)
Subtotal Accounts 4262016, 4262041	(2,437,454.26)
Penalties	-
Subtotal Account 4263001	-
Certain Civic, Political & Related Activities	4,583,541.86
Subtotal Accounts 4264100, 4264200, 4264300	4,583,541.86
Other Deductions	1,111,780.31
Subtotal Account 4265001	1,111,780.31
Total Miscellaneous Income Deductions - Account 426	8,802,855.06
Account 430 - Interest on Debt to Associated Companies	
Money Pool (Avg Rate 5.2%)	1,483,069.49
Total Interest on Debt to Associated Companies - Account 430	1,483,069.49
Account 431 - Other Interest Expense	
Commitment Fees (4310010)	346,808.86
Other Interest Expense (4310001, 4310011)	755,831.35
Customer Deposits - Rate 6 to 7% per annum	9,369,863.82
Interest related to Projected Tax Refund - Rate 6.5%	(2,952,329.00)
Interest related to Projected Tax Deficiency on various audit issues - Rate 6.5%	(361,966.02)
Total Other Interest Expense - Account 431	7,158,209.01

Progress Energy

Will Garrett
Controller – Progress Energy Florida

07 MAY 23 AM 11:32
FLORIDA PUBLIC SERVICE
DIVISION OF
ECONOMIC REGULATION

May 21, 2007

Ms. Betty Gardner
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0865

Dear Ms. Gardner:

Per your request, we are filing our Annual Status report of depreciation-related data for 2006 directly with your office rather than enclosing it with the FERC Form 1 Report.

Sincerely,

Will Garrett
Controller–Progress Energy Florida

WG/shm

Enclosure

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

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101 AND ACCOUNT 106
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
PRIMARY ACCOUNT 311	-	-	-	-	-
PRIMARY ACCOUNT 312	-	-	-	-	-
PRIMARY ACCOUNT 314	-	-	-	-	-
PRIMARY ACCOUNT 315	-	-	-	-	-
PRIMARY ACCOUNT 316.1	-	-	-	-	-
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	-	-	-	-	-
SUWANNEE					
PRIMARY ACCOUNT 311	5,064,160	-	-	-	5,064,160
PRIMARY ACCOUNT 312	14,661,539	273,280	65,459	-	14,869,360
PRIMARY ACCOUNT 314	11,090,453	10,222	7,539	-	11,093,136
PRIMARY ACCOUNT 315	2,672,089	53,066	5,279	-	2,719,875
PRIMARY ACCOUNT 316.1	439,403	-	-	-	439,403
PRIMARY ACCOUNT 316.2 (5 YEAR)	7,170	-	-	-	7,170
PRIMARY ACCOUNT 316.3 (7 YEAR)	13,658	15,956	-	-	29,614
PRIMARY ACCOUNT 317	2,366,374	0	-	-	2,366,374
TOTAL	36,314,846	352,524	78,277	-	36,589,093
TURNER					
PRIMARY ACCOUNT 311	-	-	-	-	-
PRIMARY ACCOUNT 312	-	-	-	-	-
PRIMARY ACCOUNT 314	-	-	-	-	-
PRIMARY ACCOUNT 315	-	-	-	-	-
PRIMARY ACCOUNT 316.1	-	-	-	-	-
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 317	586,347	(0)	-	-	586,347
TOTAL	586,347	(0)	-	-	586,347
BARTOW-ANCLOTE PIPELINE					
PRIMARY ACCOUNT 311	1,111,324	-	-	-	1,111,324
PRIMARY ACCOUNT 312	17,010,912	-	-	-	17,010,912
PRIMARY ACCOUNT 315	1,252,617	-	-	-	1,252,617
PRIMARY ACCOUNT 316.1	152,597	-	-	-	152,597
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	8,731	-	-	-	8,731
PRIMARY ACCOUNT 317	212,667	(0)	-	-	212,667
TOTAL	19,748,848	(0)	-	-	19,748,848
CRYSTAL RIVER 1&2 COAL PILE					
PRIMARY ACCOUNT 312	1,023,482	-	-	-	1,023,482
CRYSTAL RIVER 4&5 COAL PILE					
PRIMARY ACCOUNT 312	1,727,433	-	-	-	1,727,433
STEAM SYSTEM 5 YEAR - 316.2	558,132	-	-	-	558,132
STEAM SYSTEM 7 YEAR - 316.3	461,957	(21,064)	-	-	440,893
TOTAL STEAM PRODUCTION	1,763,329,873	62,858,261	10,044,790	243,627	1,816,386,970

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101 AND ACCOUNT 106
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
NUCLEAR PRODUCTION					
CRYSTAL RIVER#3					
PRIMARY ACCOUNT 321	220,626,715	1,826,083	774,472	171,538	221,849,863
PRIMARY ACCOUNT 322	264,248,689	3,053,922	6,315,402	-	260,987,209
PRIMARY ACCOUNT 323	91,786,585	1,064,504	394,285	-	92,456,804
PRIMARY ACCOUNT 324	176,737,667	4,011,361	1,233,813	(221,430)	179,293,785
PRIMARY ACCOUNT 325.1	33,142,155	1,454,496	263,021	(90,360)	33,925,660
PRIMARY ACCOUNT 325.2	2,589,910	77,422	27,709	13,524	2,653,147
PRIMARY ACCOUNT 325.3	4,282,615	827	-	-	4,283,441
TOTAL NUCLEAR PRODUCTION	793,474,197	11,488,615	9,008,702	(126,728)	795,827,383
ARO					
PRIMARY ACCOUNT 326	50,847	55,711,909	-	(55,711,909)	50,847
TOTAL NUCLEAR	793,525,044	67,200,524	9,008,702	(55,838,637)	795,878,230
OTHER PRODUCTION					
AVON PARK	8,914,673	-	-	-	8,914,673
BARTOW	25,081,280	37,170	-	-	25,118,450
BAYBORO	24,286,533	831,414	755,546	-	24,362,401
DEBARY	53,778,151	350,763	379,965	-	53,748,949
HIGGINS	17,765,704	77,979	-	-	17,843,683
INTERCESSION CITY	36,894,709	545,809	-	-	37,440,518
PORT ST. JOE	-	-	-	-	-
RIO PINAR	2,934,069	-	-	-	2,934,069
SUWANNEE	29,132,050	337,398	56,529	-	29,412,919
TURNER	22,765,457	-	-	-	22,765,457
DEBARY (NEW)	100,036,971	-	334,314	-	99,702,658
INTERCESSION CITY (NEW)	103,812,971	-	-	-	103,812,971
GAS CONVERSION SITES	(1,499,216)	-	-	-	(1,499,216)
UNIVERSITY OF FLORIDA	44,067,138	141,435	149,516	-	44,059,056
INTERCESSION CITY - SIEMENS	23,290,932	-	2,733	-	23,288,199
TIGER BAY	91,502,172	-	10,967,443	-	80,534,728
HINES ENERGY COMPLEX	780,597,707	2,798,845	8,844,069	-	774,552,482
INTERCESSION CITY P12-14	94,412,017	204,438	-	-	94,616,455
SYSTEM 5 YEAR	27,945	-	-	-	27,945
SYSTEM 7 YEAR	27,203	-	-	-	27,203
TOTAL OTHER PRODUCTION	1,458,285,043	4,891,875	21,490,114	-	1,441,686,803
TRANSMISSION PLANT					
350.1 TRANSMISSION EASEMENTS	47,099,087	-	2,000	-	47,097,087
352 STRUCTURES	20,661,266	1,991,937	1,090,371	(36,404)	21,526,428
353 STATION EQUIPMENT	391,997,571	1,898,569	-	(752,843)	393,143,297
353.1 ENERGY CONTROL CENTER	43,188,463	34,311,630	1,989,522	(155,988)	75,354,583
354 TOWERS AND FIXTURES	66,464,849	901	-	-	66,465,750
355 POLES AND FIXTURES	264,013,369	63,594,947	699,157	(821,843)	326,087,315
356 OVERHEAD CONDUCTOR	213,972,008	21,216,957	378,521	(73,835)	234,736,608
357 UNDERGROUND CONDUIT	7,010,980	-	-	-	7,010,980
358 UNDERGROUND CONDUCTOR	9,496,402	102,185	-	-	9,598,587

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101 AND ACCOUNT 106
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
359 MISCELLANEOUS PLANT EQUIP.	1,923,606	1,210,296	-	-	3,133,902
TOTAL TRANSMISSION PLANT	1,065,827,600	124,327,423	4,159,571	(1,840,914)	1,184,154,538
DISTRIBUTION PLANT					
360.1 TRANSMISSION EASEMENTS	557,015	-	-	-	557,015
361 STRUCTURES	22,287,897	1,630,767	45,528	(23,515)	23,849,621
362 STATION EQUIPMENT	356,918,497	27,845,525	911,975	(301,811)	383,550,236
364 POLES AND FIXTURES	439,090,560	27,222,564	1,080,417	(756,965)	464,475,743
365 OVERHEAD CONDUCTOR	482,604,644	34,688,407	4,485,679	1,228,160	514,035,532
366 UNDERGROUND CONDUIT	172,411,514	21,113,141	213,486	(52,035)	193,259,134
367 UNDERGROUND CONDUCTOR	441,851,517	28,060,461	2,865,090	(392,684)	466,654,205
368 LINE TRANSFORMER	410,885,432	43,789,139	3,920,993	32,158	450,785,736
369.1 OVERHEAD SERVICES	77,151,063	826,001	868,329	-	77,108,735
369.2 UNDERGROUND SERVICES	356,666,896	33,852,438	9,952,699	(784,978)	379,781,656
370 METERS	133,985,854	61,536,218	82,445,030	(7,425)	113,069,617
370.1 ENERGY CONSER. METERS	-	-	-	-	-
371 INSTALL ON CUST. PREM.	2,222,150	-	-	-	2,222,150
372 LEASED PROPERTY	-	-	-	-	-
373 STREET LIGHTING	267,101,836	18,269,113	2,672,733	(7,461,445)	275,236,771
TOTAL DISTRIBUTION PLANT	3,163,734,875	298,833,775	109,461,959	(8,520,541)	3,344,586,150
GENERAL PLANT					
390 STRUCTURES	94,424,830	20,478,771	831,000	62,329	114,134,930
391.1 OFFICE FURNITURE	5,795,467	942,791	807,229	-	5,931,029
391.2 OFFICE EQUIPMENT	77,315	4,812	-	-	82,127
391.3 COMPUTERS	3,586,713	95,035	190,831	-	3,490,918
391.5 DUPLICATING EQUIPMENT	1,013,615	-	152,032	-	861,583
393 STORES EQUIPMENT	-	-	-	-	-
393.1 MOTORIZED HANDLING EQUIP.	3,029,288	644,901	46,555	-	3,627,634
393.2 STORAGE EQUIPMENT	318,843	73,396	17,254	-	374,985
393.3 PORTABLE HANDLING EQUIP.	3,893	-	-	-	3,893
394 TOOLS, SHOP & GARAGE EQUIP.	1,037,942	119,491	8,722	-	1,148,710
394.1 TOOLS, SHOP & GARAGE EQUIP.	6,469,165	1,435,844	88	-	7,904,921
394.2 TOOLS, SHOP & GARAGE EQUIP.	3,650,643	948,693	42,725	-	4,556,611
395 LABORATORY EQUIPMENT	4,483	8,569	-	-	13,052
395.2 PORTABLE LABORATORY EQUIP.	3,183,836	185,021	267,524	-	3,101,334
396 POWER OPERATED EQUIPMENT	3,349,676	657,713	-	-	4,007,389
397 COMMUNICATIONS EQUIPMENT	31,000,865	1,748,401	62,063	(2,946)	32,684,258
397.1 COMMUNICATIONS EQUIPMENT	26,737,896	370,943	376,804	-	26,732,035
398.1 ENERGY CONSERVATION	49,419	-	-	-	49,419
398.2 MISCELLANEOUS EQUIPMENT	3,634,825	2,745,622	409,985	-	5,970,462
399.1 ARO GENERAL PLANT	1,974,239	(0)	-	(1)	1,974,238
TOTAL GENERAL PLANT	189,342,952	30,460,003	3,212,810	59,383	216,649,528
TRANSPORTATION EQUIPMENT					
392.1 PASSENGER CARS	1,000,595	32,346	43,915	-	989,026
392.2 LIGHT TRUCKS	18,189,104	3,308,460	194,924	-	21,302,640
392.3 HEAVY TRUCKS	14,313,030	1,894,513	-	-	16,207,543

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101 AND ACCOUNT 106
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
392.4 SPECIAL EQUIPMENT	86,004,110	12,252,803	1,043,101	-	97,213,812
392.5 TRAILERS	8,465,767	57,176	-	-	8,522,943
392.6 AIRCRAFT (USED)	-	-	-	-	-
392.7 AIRCRAFT (NEW)	-	-	-	-	-
TOTAL TRANSPORTATION EQUIPMENT	127,972,606	17,545,299	1,281,940	-	144,235,965
TOTAL GENERAL PLANT	317,315,558	48,005,303	4,494,750	59,383	360,885,493
		48,005,303	4,460,554	59,383	
			34,196	(0)	
INTANGIBLE	61,637,865	5,010,102	-	-	66,647,967
INTANGIBLE - CSS	61,959,582	2,048,276	-	-	64,007,858
TOTAL ELECTRIC PLANT IN SERVICE	8,685,615,440	613,175,538	158,659,887	(65,897,083)	9,074,234,010

NOTE: DOES NOT INCLUDE TRANSACTIONS FOR NON-DEPRECIABLE PROPERTY.

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
STEAM PRODUCTION					
ANCLOTE					
PRIMARY ACCOUNT 311	37,352,214	11,920	118,275	-	37,245,860
PRIMARY ACCOUNT 312	102,437,787	470,427	4,010,688	-	98,897,527
PRIMARY ACCOUNT 314	93,478,474	98,416	1,741,113	-	91,835,776
PRIMARY ACCOUNT 315	26,050,951	-	62,906	-	25,988,045
PRIMARY ACCOUNT 316.1	5,705,438	452,036	8,348	-	6,149,126
PRIMARY ACCOUNT 316.2 (5 YEAR)	121,812	-	-	-	121,812
PRIMARY ACCOUNT 316.3 (7 YEAR)	199,857	24,111	-	-	223,967
PRIMARY ACCOUNT 317	315,962	(0)	-	-	315,962
TOTAL	265,662,495	1,056,910	5,941,329	-	260,778,075
AVON PARK					
TOTAL ALL PRIMARY ACCOUNTS					
BARTOW					
PRIMARY ACCOUNT 311	18,126,761	104,571	-	-	18,231,332
PRIMARY ACCOUNT 312	59,487,475	883,371	226,466	-	60,144,380
PRIMARY ACCOUNT 314	25,960,166	-	58,404	-	25,901,762
PRIMARY ACCOUNT 315	13,666,614	-	30,896	-	13,635,718
PRIMARY ACCOUNT 316.1	3,281,803	28,746	3,011	-	3,307,538
PRIMARY ACCOUNT 316.2 (5 YEAR)	186,422	-	-	-	186,422
PRIMARY ACCOUNT 316.3 (7 YEAR)	76,130	42,327	-	-	118,457
PRIMARY ACCOUNT 317	1,717,302	(0)	-	-	1,717,302
TOTAL	122,502,673	1,059,015	318,777	-	123,242,912
CRYSTAL RIVER 1&2					
PRIMARY ACCOUNT 311	74,776,694	79,529	698	-	74,855,524
PRIMARY ACCOUNT 312	166,378,723	18,627,523	257,989	-	184,748,257
PRIMARY ACCOUNT 314	117,704,299	6,042,285	23,330	-	123,723,254
PRIMARY ACCOUNT 315	34,445,297	122,610	-	-	34,567,907
PRIMARY ACCOUNT 316.1	5,905,534	56,565	13,802	-	5,948,297
PRIMARY ACCOUNT 316.2 (5 YEAR)	233,211	-	-	-	233,211
PRIMARY ACCOUNT 316.3 (7 YEAR)	112,800	19,064	-	-	131,865
PRIMARY ACCOUNT 317	3,683,195	0	-	-	3,683,195
TOTAL	403,239,753	24,947,576	295,819	-	427,891,510
CRYSTAL RIVER 4&5					
PRIMARY ACCOUNT 311	149,089,496	41,375	-	-	149,130,871
PRIMARY ACCOUNT 312	464,776,417	21,248,201	3,175,366	197	482,849,448
PRIMARY ACCOUNT 314	192,502,004	-	195,018	-	192,306,986
PRIMARY ACCOUNT 315	80,338,559	-	26,898	221,430	80,533,091
PRIMARY ACCOUNT 316.1	11,510,828	7,249	13,306	22,000	11,526,771
PRIMARY ACCOUNT 316.2 (5 YEAR)	149,408	-	-	-	149,408
PRIMARY ACCOUNT 316.3 (7 YEAR)	619,590	17,164	-	-	636,754
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	898,986,302	21,313,989	3,410,589	243,627	917,133,329
HIGGINS					
PRIMARY ACCOUNT 311	-	-	-	-	-

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
PRIMARY ACCOUNT 312	-	-	-	-	-
PRIMARY ACCOUNT 314	-	-	-	-	-
PRIMARY ACCOUNT 315	-	-	-	-	-
PRIMARY ACCOUNT 316.1	-	-	-	-	-
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	-	-	-	-	-
SUWANNEE					
PRIMARY ACCOUNT 311	5,064,160	-	-	-	5,064,160
PRIMARY ACCOUNT 312	14,576,930	348,946	65,459	-	14,860,417
PRIMARY ACCOUNT 314	11,090,592	-	7,539	-	11,083,053
PRIMARY ACCOUNT 315	2,615,375	109,780	5,279	-	2,719,875
PRIMARY ACCOUNT 316.1	439,403	-	-	-	439,403
PRIMARY ACCOUNT 316.2 (5 YEAR)	7,170	-	-	-	7,170
PRIMARY ACCOUNT 316.3 (7 YEAR)	13,658	15,956	-	-	29,614
PRIMARY ACCOUNT 317	2,366,374	0	-	-	2,366,374
TOTAL	36,173,661	474,682	78,277	-	36,570,066
TURNER					
PRIMARY ACCOUNT 311	-	-	-	-	-
PRIMARY ACCOUNT 312	-	-	-	-	-
PRIMARY ACCOUNT 314	-	-	-	-	-
PRIMARY ACCOUNT 315	-	-	-	-	-
PRIMARY ACCOUNT 316.1	-	-	-	-	-
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 317	586,347	(0)	-	-	586,347
TOTAL	586,347	(0)	-	-	586,347
BARTOW-ANCLOTE PIPELINE					
PRIMARY ACCOUNT 311	1,111,324	-	-	-	1,111,324
PRIMARY ACCOUNT 312	15,474,640	1,536,272	-	-	17,010,912
PRIMARY ACCOUNT 315	1,252,617	-	-	-	1,252,617
PRIMARY ACCOUNT 316.1	152,597	-	-	-	152,597
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	8,731	-	-	-	8,731
PRIMARY ACCOUNT 317	212,667	(0)	-	-	212,667
TOTAL	18,212,576	1,536,272	-	-	19,748,848
CRYSTAL RIVER 1&2 COAL PILE					
PRIMARY ACCOUNT 312	1,023,482	-	-	-	1,023,482
CRYSTAL RIVER 4&5 COAL PILE					
PRIMARY ACCOUNT 312	1,727,433	-	-	-	1,727,433
STEAM SYSTEM 5 YEAR - 316.2	558,132	-	-	-	558,132
STEAM SYSTEM 7 YEAR - 316.3	413,712	-	-	-	413,712
TOTAL STEAM PRODUCTION	1,749,086,566	50,388,443	10,044,790	243,627	1,789,673,846

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
NUCLEAR PRODUCTION					
CRYSTAL RIVER#3					
PRIMARY ACCOUNT 321	220,487,468	1,887,856	774,472	171,538	221,772,390
PRIMARY ACCOUNT 322	264,143,622	3,158,989	6,315,402	-	260,987,209
PRIMARY ACCOUNT 323	91,723,369	1,127,720	394,285	-	92,456,804
PRIMARY ACCOUNT 324	176,737,667	3,655,444	1,233,813	(221,430)	178,937,868
PRIMARY ACCOUNT 325.1	33,099,687	1,136,886	263,021	(90,360)	33,883,192
PRIMARY ACCOUNT 325.2	2,473,201	-	27,709	13,524	2,459,016
PRIMARY ACCOUNT 325.3	4,329,742	70,408	-		4,400,150
TOTAL NUCLEAR PRODUCTION	792,994,754	11,037,304	9,008,702	(126,728)	794,896,628
ARO					
PRIMARY ACCOUNT 326	50,847	55,711,909	-	(55,711,909)	50,847
OTHER PRODUCTION					
AVON PARK	8,914,673	-	-	-	8,914,673
BARTOW	24,522,766	-	-	-	24,522,766
BAYBORO	24,055,915	94,883	755,546	-	23,395,252
DEBARY	53,778,152	76,223	379,965	-	53,474,410
DEBARY (NEW)	99,271,013	-	334,314	-	98,936,700
HIGGINS	17,765,705	77,979	-	-	17,843,684
HINES ENERGY COMPLEX	271,410,091	12,773,150	8,844,069	-	275,339,171
INTERCESSION CITY P1-6	35,179,024	231,213	-	-	35,410,237
INTERCESSION CITY (NEW) P7-10	103,812,971	-	-	-	103,812,971
INTERCESSION CITY P12-14	94,412,018	-	-	-	94,412,018
INTERCESSION CITY - SIEMENS (P11)	23,277,222	13,710	2,733	-	23,288,199
PORT ST. JOE	-	-	-	-	-
RIO PINAR	2,934,069	-	-	-	2,934,069
SUWANNEE	28,722,332	62,335	56,529	-	28,728,138
TIGER BAY	78,908,507	-	10,967,443	-	67,941,064
TURNER	22,765,457	-	-	-	22,765,457
GAS CONVERSION SITES	(1,499,216)	-	-	-	(1,499,216)
UNIVERSITY OF FLORIDA	43,840,575	226,562	149,516	-	43,917,621
SYSTEM 5 YEAR	27,945	-	-	-	27,945
SYSTEM 7 YEAR	(661,844)	-	-	-	(661,844)
TOTAL OTHER PRODUCTION	931,437,375	13,556,055	21,490,114	-	923,503,315
TRANSMISSION PLANT					
350.1 TRANSMISSION EASEMENTS	47,099,087	-	2,000	-	47,097,087
352 STRUCTURES	17,545,010	4,205,863	1,090,371	(36,404)	20,624,099
353 STATION EQUIPMENT	383,929,019	602	-	(752,843)	383,176,777
353.1 ENERGY CONTROL CENTER	33,989,443	13,846,986	1,989,522	(155,988)	45,690,919
354 TOWERS AND FIXTURES	66,443,467	901	-	-	66,444,368
355 POLES AND FIXTURES	248,567,003	15,408,137	699,157	(821,843)	262,454,140
356 OVERHEAD CONDUCTOR	208,841,827	5,835,928	378,521	(73,835)	214,225,398
357 UNDERGROUND CONDUIT	7,010,980	-	-	-	7,010,980
358 UNDERGROUND CONDUCTOR	9,496,402	102,185	-	-	9,598,587
359 MISCELLANEOUS PLANT EQUIP.	1,923,606	1,210,296	-	-	3,133,902

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
TOTAL TRANSMISSION PLANT	1,024,845,844	40,610,897	4,159,571	(1,840,914)	1,059,456,257
DISTRIBUTION PLANT					
360.1 TRANSMISSION EASEMENTS	557,015	-	-	-	557,015
361 STRUCTURES	21,929,274	525,913	45,528	(23,515)	22,386,145
362 STATION EQUIPMENT	344,833,440	10,302,765	911,975	(301,811)	353,922,419
364 POLES AND FIXTURES	434,336,567	22,603,884	1,080,417	(756,965)	455,103,069
365 OVERHEAD CONDUCTOR	455,509,674	44,356,000	4,485,679	1,228,160	496,608,155
366 UNDERGROUND CONDUIT	167,267,602	18,152,266	213,486	(52,035)	185,154,347
367 UNDERGROUND CONDUCTOR	433,621,038	23,279,532	2,865,090	(392,684)	453,642,796
368 LINE TRANSFORMER	397,348,083	45,066,344	3,920,993	32,158	438,525,592
369.1 OVERHEAD SERVICES	76,867,777	713,786	868,329	-	76,713,234
369.2 UNDERGROUND SERVICES	347,610,503	31,818,168	9,952,699	(784,978)	368,690,994
370 METERS	122,011,382	(567,742)	82,445,030	(7,425)	38,991,186
370.1 ENERGY CONSER. METERS	-	-	-	-	-
371 INSTALL ON CUST. PREM.	2,222,150	-	-	-	2,222,150
372 LEASED PROPERTY	-	-	-	-	-
373 STREET LIGHTING	264,738,553	15,688,177	2,672,733	(7,461,445)	270,292,551
TOTAL DISTRIBUTION PLANT	3,068,853,058	211,939,094	109,461,959	(8,520,541)	3,162,809,653
GENERAL PLANT					
390 STRUCTURES	93,632,272	8,270,052	831,000	62,329	101,133,653
391.1 OFFICE FURNITURE	5,791,961	373,905	807,229	-	5,358,637
391.2 OFFICE EQUIPMENT	77,315	4,812	-	-	82,127
391.3 COMPUTERS	3,374,744	12,825	190,831	-	3,196,738
391.5 DUPLICATING EQUIPMENT	993,681	-	152,032	-	841,649
393 STORES EQUIPMENT	-		-	-	-
393.1 MOTORIZED HANDLING EQUIP.	2,953,111	644,823	46,555	-	3,551,379
393.2 STORAGE EQUIPMENT	154,281	235,218	17,254	-	372,245
393.3 PORTABLE HANDLING EQUIP.	-	-		-	-
394 TOOLS, SHOP & GARAGE EQUIP.	581,845	183,063	8,722	-	756,187
394.1 TOOLS, SHOP & GARAGE EQUIP.	6,375,401	1,463,984	88	-	7,839,297
394.2 TOOLS, SHOP & GARAGE EQUIP.	2,686,148	993,294	42,725	-	3,636,717
395 LABORATORY EQUIPMENT	4,483			-	4,483
395.2 PORTABLE LABORATORY EQUIP.	2,804,526	219,467	267,524	-	2,756,469
396 POWER OPERATED EQUIPMENT	2,790,514	974,861	-	-	3,765,375
397 COMMUNICATIONS EQUIPMENT	30,172,663	874,194	62,063	(2,946)	30,981,848
397.1 COMMUNICATIONS EQUIPMENT	24,654,409	180,061	376,804	-	24,457,666
398.1 ENERGY CONSERVATION	49,418	-		-	49,418
398.2 MISCELLANEOUS EQUIPMENT	2,503,506	427,495	409,985	-	2,521,016
399.1 ARO GENERAL PLANT	1,974,239	(0)	-	(1)	1,974,238
TOTAL GENERAL PLANT	181,574,517	14,858,052	3,212,810	59,383	193,279,142
TRANSPORTATION EQUIPMENT					
392.1 PASSENGER CARS	1,000,595	32,346	43,915	-	989,026
392.2 LIGHT TRUCKS	17,915,610	1,328,355	194,924	-	19,049,041
392.3 HEAVY TRUCKS	14,161,631	129,439	-	-	14,291,070
392.4 SPECIAL EQUIPMENT	82,495,913	7,992,177	1,043,101	-	89,444,989
392.5 TRAILERS	7,587,136	800,748	-	-	8,387,884

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
392.6 AIRCRAFT (USED)	-	-	-	-	-
392.7 AIRCRAFT (NEW)	-	-	-	-	-
TOTAL TRANSPORTATION EQUIPMENT	123,160,885	10,283,065	1,281,940	-	132,162,009
INTANGIBLE (303)	61,025,587	-	-	-	61,025,587
INTANGIBLE - CSS (302)	55,600,654	2,048,276	-	-	57,648,930
TOTAL ELECTRIC PLANT IN SERVICE	7,988,630,088	410,433,095	158,659,887	(65,897,083)	8,174,506,215

NOTE: DOES NOT INCLUDE TRANSACTIONS FOR NON-DEPRECIABLE PROPERTY.

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 106
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
STEAM PRODUCTION					
ANCLOTE					
PRIMARY ACCOUNT 311	-	403,077	-	-	403,077
PRIMARY ACCOUNT 312	403,582	6,622,978	-	-	7,026,560
PRIMARY ACCOUNT 314	-	6,202,496	-	-	6,202,496
PRIMARY ACCOUNT 315	-	483,288	-	-	483,288
PRIMARY ACCOUNT 316.1	-	86,342	-	-	86,342
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	-	52,197	-	-	52,197
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	403,582	13,850,378	-	-	14,253,960
AVON PARK					
TOTAL ALL PRIMARY ACCOUNTS	-	-	-	-	-
BARTOW					
PRIMARY ACCOUNT 311	-	-	-	-	-
PRIMARY ACCOUNT 312	2,998,369	(321,011)	-	-	2,677,359
PRIMARY ACCOUNT 314	198,261	166,292	-	-	364,553
PRIMARY ACCOUNT 315	(0)	61,938	-	-	61,938
PRIMARY ACCOUNT 316.1	28,746	(20,274)	-	-	8,471
PRIMARY ACCOUNT 316.2 (5 YEAR)	(14,738)	-	-	-	(14,738)
PRIMARY ACCOUNT 316.3 (7 YEAR)	70,995	160,916	-	-	231,910
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	3,281,633	47,860	-	-	3,329,493
CRYSTAL RIVER 1&2					
PRIMARY ACCOUNT 311	87,665	(49,704)	-	-	37,961
PRIMARY ACCOUNT 312	93,597	622,364	-	-	715,960
PRIMARY ACCOUNT 314	6,042,286	(6,042,285)	-	-	1
PRIMARY ACCOUNT 315	-	528,265	-	-	528,265
PRIMARY ACCOUNT 316.1	-	85,241	-	-	85,241
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	15,319	-	-	-	15,319
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	6,238,868	(4,856,120)	-	-	1,382,748
CRYSTAL RIVER 4&5					
PRIMARY ACCOUNT 311	-	65,982	-	-	65,982
PRIMARY ACCOUNT 312	2,593,507	4,182,054	-	-	6,775,561
PRIMARY ACCOUNT 314	17	589,951	-	-	589,968
PRIMARY ACCOUNT 315	-	59,145	-	-	59,145
PRIMARY ACCOUNT 316.1	-	13,172	-	-	13,172
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	(1)	196,891	-	-	196,889
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	2,593,523	5,107,194	-	-	7,700,717
HIGGINS					
PRIMARY ACCOUNT 311	-	-	-	-	-

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 106
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
PRIMARY ACCOUNT 312	-	-	-	-	-
PRIMARY ACCOUNT 314	-	-	-	-	-
PRIMARY ACCOUNT 315	-	-	-	-	-
PRIMARY ACCOUNT 316.1	-	-	-	-	-
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	-	-	-	-	-
SUWANNEE					
PRIMARY ACCOUNT 311	(0)	-	-	-	(0)
PRIMARY ACCOUNT 312	84,610	(75,666)	-	-	8,943
PRIMARY ACCOUNT 314	(139)	10,222	-	-	10,083
PRIMARY ACCOUNT 315	56,714	(56,714)	-	-	-
PRIMARY ACCOUNT 316.1	-	-	-	-	-
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	141,184	(122,158)	-	-	19,026
TURNER					
PRIMARY ACCOUNT 311	-	-	-	-	-
PRIMARY ACCOUNT 312	-	-	-	-	-
PRIMARY ACCOUNT 314	-	-	-	-	-
PRIMARY ACCOUNT 315	-	-	-	-	-
PRIMARY ACCOUNT 316.1	-	-	-	-	-
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	-	-	-	-	-
BARTOW-ANCLOTE PIPELINE					
PRIMARY ACCOUNT 311	-	-	-	-	-
PRIMARY ACCOUNT 312	1,536,272	(1,536,272)	-	-	-
PRIMARY ACCOUNT 315	-	-	-	-	-
PRIMARY ACCOUNT 316.1	-	-	-	-	-
PRIMARY ACCOUNT 316.2 (5 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 316.3 (7 YEAR)	-	-	-	-	-
PRIMARY ACCOUNT 317	-	-	-	-	-
TOTAL	1,536,272	(1,536.272)	-	-	-
CRYSTAL RIVER 1&2 COAL PILE					
PRIMARY ACCOUNT 312	-	-	-	-	-
CRYSTAL RIVER 4&5 COAL PILE					
PRIMARY ACCOUNT 312	-	-	-	-	-
STEAM SYSTEM 5 YEAR - 316.2	-	-	-	-	-
STEAM SYSTEM 7 YEAR - 316.3	48,245	(21,064)	-	-	27,181
TOTAL STEAM PRODUCTION	14,243,306	12,469,818	-	-	26,713,125

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 106
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
NUCLEAR PRODUCTION					
CRYSTAL RIVER#3					
PRIMARY ACCOUNT 321	139,247	(61,773)	-	-	77,474
PRIMARY ACCOUNT 322	105,067	(105,067)	-	-	(0)
PRIMARY ACCOUNT 323	63,216	(63,216)	-	-	(0)
PRIMARY ACCOUNT 324	-	355,918	-	-	355,918
PRIMARY ACCOUNT 325	59,862	317,610	-	-	377,473
PRIMARY ACCOUNT 325.1	42,468	-	-	-	42,468
PRIMARY ACCOUNT 325.2	116,709	77,422	-	-	194,131
PRIMARY ACCOUNT 325.3	(47,127)	(69,582)	-	-	(116,709)
TOTAL NUCLEAR PRODUCTION	479,442	451,312	-	-	930,754
ARO					
PRIMARY ACCOUNT 326	-	-	-	-	-
OTHER PRODUCTION					
AVON PARK	0		-	-	0
BARTOW	558,515	37,170	-	-	595,685
BAYBORO	230,619	736,531	-	-	967,149
DEBARY (Common, 1-6)	(1)	274,540	-	-	274,539
HIGGINS	(1)		-	-	(1)
INTERCESSION CITY (1-6)	1,715,685	314,596	-	-	2,030,281
PORT ST. JOE	-		-	-	-
RIO PINAR	-		-	-	-
SUWANNEE	409,718	275,063	-	-	684,781
TURNER	0		-	-	0
DEBARY (NEW) (7-10)	765,958		-	-	765,958
INTERCESSION CITY (NEW) (7-10)	0		-	-	0
GAS CONVERSION SITES	-		-	-	-
UNIVERSITY OF FLORIDA	226,563	(85,128)	-	-	141,435
INTERCESSION CITY - SIEMENS (P11)	13,710	(13,710)	-	-	-
TIGER BAY	12,593,664		-	-	12,593,664
HINES ENERGY COMPLEX	509,187,616	(9,974,305)	-	-	499,213,311
INTERCESSION CITY P12-14	(1)	204,438	-	-	204,437
CR 3	65,978	(65,978)	-	-	-
SYSTEM - Other	390,598	(367,398)	-	-	23,200
SYSTEM 5 YEAR	-		-	-	-
SYSTEM 7 YEAR	689,047	-	-	-	689,047
TOTAL OTHER PRODUCTION	526,847,668	(8,664,181)	-	-	518,183,488
TRANSMISSION PLANT					
350.1 TRANSMISSION EASEMENTS	-	-			-
352 STRUCTURES	3,116,256	(2,213,926)	-	-	902,330
353 STATION EQUIPMENT (incl 353.2)	8,068,552	1,897,968	-	-	9,966,520
353.1 ENERGY CONTROL CENTER	9,199,020	20,464,644	-	-	29,663,664
354 TOWERS AND FIXTURES	21,382		-	-	21,382
355 POLES AND FIXTURES	15,446,365	48,186,810	-	-	63,633,176
356 OVERHEAD CONDUCTOR	5,130,180	15,381,029	-	-	20,511,210
357 UNDERGROUND CONDUIT	-	-	-	-	-
358 UNDERGROUND CONDUCTOR	-	-	-	-	-

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 106
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
359 MISCELLANEOUS PLANT EQUIP.	-	-	-	-	-
TOTAL TRANSMISSION PLANT	40,981,756	83,716,525	-	-	124,698,281
DISTRIBUTION PLANT					
360.1 TRANSMISSION EASEMENTS	-	-	-	-	-
361 STRUCTURES	358,623	1,104,853	-	-	1,463,477
362 STATION EQUIPMENT	12,085,057	17,542,760	-	-	29,627,817
364 POLES AND FIXTURES	4,753,993	4,618,680	-	-	9,372,674
365 OVERHEAD CONDUCTOR	27,094,969	(9,667,592)	-	-	17,427,377
366 UNDERGROUND CONDUIT	5,143,912	2,960,875	-	-	8,104,787
367 UNDERGROUND CONDUCTOR	8,230,480	4,780,929	-	-	13,011,408
368 LINE TRANSFORMER	13,537,349	(1,277,205)	-	-	12,260,144
369.1 OVERHEAD SERVICES	283,285	112,215	-	-	395,501
369.2 UNDERGROUND SERVICES	9,056,393	2,034,269	-	-	11,090,662
370 METERS	11,974,471	62,103,960	-	-	74,078,431
370.1 ENERGY CONSER. METERS	-	-	-	-	-
371 INSTALL ON CUST. PREM.	(0)	-	-	-	(0)
372 LEASED PROPERTY	-	-	-	-	-
373 STREET LIGHTING	2,363,284	2,580,936	-	-	4,944,220
TOTAL DISTRIBUTION PLANT	94,881,817	86,894,681	-	-	181,776,498
GENERAL PLANT					
390 STRUCTURES	792,558	12,208,719	-	-	13,001,276
391.1 OFFICE FURNITURE	3,506	568,886	-	-	572,391
391.2 OFFICE EQUIPMENT	-	-	-	-	-
391.3 COMPUTERS	211,969	82,210	-	-	294,180
391.5 DUPLICATING EQUIPMENT	19,934	-	-	-	19,934
393 STORES EQUIPMENT	-	-	-	-	-
393.1 MOTORIZED HANDLING EQUIP.	76,178	78	-	-	76,256
393.2 STORAGE EQUIPMENT	164,562	(161,822)	-	-	2,740
393.3 PORTABLE HANDLING EQUIP.	3,893	-	-	-	3,893
394 TOOLS, SHOP & GARAGE EQUIP.	456,096	(63,572)	-	-	392,524
394.1 TOOLS, SHOP & GARAGE EQUIP.	93,764	(28,139)	-	-	65,625
394.2 TOOLS, SHOP & GARAGE EQUIP.	964,495	(44,601)	-	-	919,893
395 LABORATORY EQUIPMENT	-	8,569	-	-	8,569
395.2 PORTABLE LABORATORY EQUIP.	379,310	(34,446)	-	-	344,865
396 POWER OPERATED EQUIPMENT	559,162	(317,148)	-	-	242,014
397 COMMUNICATIONS EQUIPMENT	828,202	874,208	-	-	1,702,409
397.1 COMMUNICATIONS EQUIPMENT	2,083,487	190,882	-	-	2,274,369
398.1 ENERGY CONSERVATION	1	-	-	-	1
398.2 MISCELLANEOUS EQUIPMENT(incl :	1,131,318	2,318,128	-	-	3,449,446
TOTAL GENERAL PLANT	7,768,435	15,601,951	-	-	23,370,386
TRANSPORTATION EQUIPMENT					
392.1 PASSENGER CARS	-	-	-	-	-
392.2 LIGHT TRUCKS	273,495	1,980,105	-	-	2,253,599
392.3 HEAVY TRUCKS	151,399	1,765,074	-	-	1,916,473
392.4 SPECIAL EQUIPMENT	3,508,197	4,260,627	-	-	7,768,823

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 106
PERIOD ENDING DECEMBER 31, 2006

DESCRIPTION	BALANCE 12/31/2005	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2006
392.5 TRAILERS	878,631	(743,572)	-	-	135,059
392.6 AIRCRAFT (USED)	-	-	-	-	-
392.7 AIRCRAFT (NEW)	-	-	-	-	-
TOTAL TRANSPORTATION EQUIPMENT	4,811,721	7,262,234	-	-	12,073,956
INTANGIBLE (303)	612,278	5,010,102	-	-	5,622,380
INTANGIBLE - CSS (302)	6,358,928	-	-	-	6,358,928
TOTAL ELECTRIC PLANT IN SERVICE	696,985,352	202,742,443	-	-	899,727,795
					694,879,910.65

NOTE: DOES NOT INCLUDE TRANSACTIONS FOR NON-DEPRECIABLE PROPERTY.

PROGRESS ENERGY FLORIDA
SUMMARY OF RESERVE TRANSACTIONS - PER BOOKS
DECEMBER 31, 2006

	DESCRIPTION	RESERVE BALANCE 12/31/2005	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2006	DEPRCIATION RATE APPROVED 12/18/98 (1)
STEAM PRODUCTION									
	ANCLOTE								
	PRIMARY ACCOUNT 311	23,128,301	(118,275)	(158)	-	23,933	1,172,693	24,206,494	3.1
	PRIMARY ACCOUNT 312	72,793,958	(4,010,688)	(48,624)	-	(4,338,107)	2,870,656	67,267,196	4.9
	PRIMARY ACCOUNT 314	72,460,259	(1,741,113)	(3,649)	57,611	(5,394,562)	2,249,127	67,627,671	3.9
	PRIMARY ACCOUNT 315	19,144,513	(62,906)	-	-	(1,399,500)	551,735	18,233,842	4.4
	PRIMARY ACCOUNT 316.1	4,681,719	(8,348)	-	-	(585,338)	141,046	4,229,079	5.7
	PRIMARY ACCOUNT 316.2 (5 YEAR	121,812	-	-	-	-	-	121,812	20.0
	PRIMARY ACCOUNT 316.3 (7 YEAR	116,966	-	-	-	-	30,471	147,437	14.3
	PRIMARY ACCOUNT 317	-	-	-	-	-	2,269	2,269	
TOTAL		192,447,527	(5,941,329)	(52,431)	57,611	(11,693,574)	7,017,998	181,835,801	-
	AVON PARK	-	-	-	-	-	-	-	
	BARTOW								
	PRIMARY ACCOUNT 311	16,381,326	-	-	421,378	(916,243)	485,726	16,372,186	4.1
	PRIMARY ACCOUNT 312	51,603,569	(226,466)	(34,637)	-	(4,293,901)	1,864,616	48,913,182	6.9
	PRIMARY ACCOUNT 314	25,831,172	(58,404)	-	-	(2,556,956)	217,869	23,433,680	6.5
	PRIMARY ACCOUNT 315	13,376,593	(30,896)	-	-	(1,336,089)	248,243	12,257,851	6.5
	PRIMARY ACCOUNT 316.1	2,415,970	(3,011)	-	-	(257,590)	125,253	2,280,622	7.0
	PRIMARY ACCOUNT 316.2 (5 YEAR	143,949	-	-	-	-	27,735	171,684	20.0
	PRIMARY ACCOUNT 316.3 (7 YEAR	28,186	-	-	-	-	30,438	58,624	14.3
	PRIMARY ACCOUNT 317	-	-	-	-	-	8,714	8,714	
TOTAL		109,780,764	(318,777)	(34,637)	421,378	(9,360,779)	3,008,594	103,496,543	
	CRYSTAL RIVER 1&2								
	PRIMARY ACCOUNT 311	55,961,484	(698)	(2,737)	-	(2,901,774)	1,944,929	55,001,204	4.2
	PRIMARY ACCOUNT 312	112,191,994	(257,989)	(9,067)	-	7,234,547	7,522,714	126,682,199	5.3
	PRIMARY ACCOUNT 314	90,896,504	(23,330)	(100,177)	7,668	(8,545,297)	3,903,992	86,139,360	5.3
	PRIMARY ACCOUNT 315	25,015,036	-	(15,170)	-	(1,615,143)	1,000,290	24,385,013	4.9
	PRIMARY ACCOUNT 316.1	4,641,325	(13,802)	(1,471)	-	(481,872)	196,373	4,340,553	6.3
	PRIMARY ACCOUNT 316.2 (5 YEAR	145,206	-	-	-	-	4,202	149,408	20.0
	PRIMARY ACCOUNT 316.3 (7 YEAR	54,484	-	-	-	-	19,106	73,590	14.3
	PRIMARY ACCOUNT 317	-	-	-	-	(29,213)	103,526	74,313	
TOTAL		288,906,033	(295,819)	(128,623)	7,668	(6,338,752)	14,695,132	296,845,640	
	CRYSTAL RIVER 4&5								
	PRIMARY ACCOUNT 311	77,952,674	-	(2,354)	-	-	4,961,451	82,911,772	3.0
	PRIMARY ACCOUNT 312	345,512,804	(3,175,366)	(165,519)	-	(1,411,983)	13,950,745	354,710,681	3.5
	PRIMARY ACCOUNT 314	147,788,207	(195,018)	-	-	(10,797,579)	4,153,493	140,949,102	5.0
	PRIMARY ACCOUNT 315	52,778,130	(26,898)	-	-	(2,217,547)	2,206,615	52,740,300	3.7
	PRIMARY ACCOUNT 316.1	7,787,126	(13,306)	-	-	(785,394)	370,537	7,358,963	5.1
	PRIMARY ACCOUNT 316.2 (5 YEAR	233,211	-	-	-	-	-	233,211	20.0
	PRIMARY ACCOUNT 316.3 (7 YEAR	382,603	-	-	-	-	93,246	471,204	14.3
	PRIMARY ACCOUNT 317	-	-	-	-	-	-	-	
TOTAL		632,434,755	(3,410,589)	(167,873)	-	(15,212,503)	25,736,088	639,375,233	
	HIGGINS								
	PRIMARY ACCOUNT 311	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 312	-	-	-	-	-	-	-	-

PROGRESS ENERGY FLORIDA
SUMMARY OF RESERVE TRANSACTIONS - PER BOOKS
DECEMBER 31, 2006

	DESCRIPTION	RESERVE BALANCE 12/31/2005	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2006	DEPRCIATION RATE APPROVED 12/18/98 (1)
	PRIMARY ACCOUNT 314	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 315	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 316.1	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 316.2 (5 YEAR	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 316.3 (7 YEAR	-	-	-	-	-	-	-	-
TOTAL		-	-	-	-	-	-	-	
	SUWANNEE								
	PRIMARY ACCOUNT 311	4,844,566	-	-	-	(295,324)	75,917	4,625,159	
	PRIMARY ACCOUNT 312	13,121,685	(65,459)	(12,602)	-	(665,087)	488,765	12,867,302	
	PRIMARY ACCOUNT 314	10,868,970	(7,539)	-	-	(674,528)	183,083	10,369,986	
	PRIMARY ACCOUNT 315	2,005,288	(5,279)	(4,562)	-	(147,629)	40,759	1,888,577	
	PRIMARY ACCOUNT 316.1	438,481	-	-	-	(28,152)	12,185	422,514	
	PRIMARY ACCOUNT 316.2 (5 YEAR	4,097	-	-	-	-	1,434	5,531	20.0
	PRIMARY ACCOUNT 316.3 (7 YEAR	1,546	-	-	-	-	2,535	3,092	14.3
	PRIMARY ACCOUNT 317	-	-	-	-	-	83,454	83,454	
TOTAL		31,284,634	(78,277)	(17,164)	-	(1,810,721)	888,131	30,265,614	
	TURNER								
	PRIMARY ACCOUNT 311	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 312	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 314	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 315	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 316.1	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 316.2 (5 YEAR	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 316.3 (7 YEAR	-	-	-	-	-	-	-	-
	PRIMARY ACCOUNT 317	-	-	-	-	-	12,421	12,421	-
TOTAL		-	-	-	-	-	12,421	12,421	
	BARTOW-ANCLOTE PIPELINE	10,172,962	-	-	-	(5,632)	678,811	10,846,141	3.6
	CRYSTAL RIVER 1&2 COALPILE	1,023,482	-	-	-	(41,103)	5,527	987,906	0.0
	CRYSTAL RIVER 4&5 COALPILE	1,727,433	-	-	-	(159,507)	9,501	1,577,427	0.0
	SYSTEM ASSETS 316.2 (5 YEAR)	558,132	-	-	-	-	-	558,132	20.0
	SYSTEM ASSETS 316.3 (7 YEAR)	265,617	-	-	-	-	64,355	329,973	14.3
TOTAL STEAM PRODUCTION		1,268,601,339	(10,044,790)	(400,728)	486,657	(44,622,572)	52,116,557	1,266,130,830	
FOSSIL DISMANTLEMENT - STEAM									
	ANCLOTE	14,540,264	-	-	-	-	234,702	14,774,966	
	BARTOW	19,668,097	-	-	-	-	367,435	20,035,531	
	BARTOW-ANCLOTE PIPELINE	2,817,192	-	-	-	-	144,962	2,962,155	
	CRYSTAL RIVER 1&2	25,650,793	-	-	-	-	66,401	25,717,194	
	CRYSTAL RIVER 4&5	32,163,555	-	-	-	-	47,307	32,210,862	
	HIGGINS	11,621,711	-	-	-	-	-	11,621,711	
	SUWANNEE	10,512,957	-	-	-	-	-	10,512,957	
	TURNER	8,453,907	-	-	-	-	-	8,453,907	
	AVON PARK	5,410,811	-	-	-	-	-	5,410,811	
	INGLIS	88,472	-	-	-	-	-	88,472	

PROGRESS ENERGY FLORIDA
SUMMARY OF RESERVE TRANSACTIONS - PER BOOKS
DECEMBER 31, 2006

DESCRIPTION	RESERVE BALANCE 12/31/2005	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2006	DEPRCIATION RATE APPROVED 12/18/98 (1)
SUBTOTAL	130,927,760	-	-	-	-	860,807	131,788,567	
FOSSIL DISMANTLEMENT - OTHER PROD.								
BAYBORO	2,010,036	-	-	-	-	21,272	2,031,308	
HIGGINS	669,526	-	-	-	-		669,526	
AVON PARK	350,780	-	-	-	-		350,780	
DEBARY	1,149,835	-	-	-	-	9,010	1,158,845	
BARTOW	840,872	-	-	-	-		840,872	
INTERCESSION CITY	946,466	-	-	-	-	10,023	956,489	
SUWANNEE	495,662	-	-	-	-	10,077	505,739	
TURNER	847,460	-	-	-	-	15,345	862,805	
PORT ST. JOE	599,283	-	-	-	-		599,283	
RIO PINAR	680,778	-	-	-	-		680,778	
DEBARY (NEW)	2,345,348	-	-	-	-	82,464	2,427,812	
INTERCESSION CITY (NEW)	1,487,416	-	-	-	-	22,778	1,510,194	
UNIVERSITY OF FLORIDA	614,572	-	-	-	-	2,805	617,377	
TIGER BAY	397,336	-	-	-	-	2,793	400,129	
HINES	215,751	-	-	-	-	8,809	224,560	
INTERCESSION CITY SIEMENS	19,066	-	-	-	-	3,122	22,188	
INTERCESSION CITY P12-14	334,061	-	-	-	-	54,701	388,762	
SUBTOTAL	14,004,247	-	-	-	-	243,201	14,247,448	
TOTAL FOSSIL DISMANTLEMENT	144,932,007	-	-	-	-	1,104,008	146,036,015	
NUCLEAR PRODUCTION								
CRYSTAL RIVER#3								
PRIMARY ACCOUNT 321	146,542,325	(774,472)	(294,985)	-	(12,917,542)	4,168,549	136,723,874	3.6
PRIMARY ACCOUNT 322	183,190,637	(6,315,402)	(935,486)	0	(22,408,806)	6,134,561	159,665,505	4.9
PRIMARY ACCOUNT 323	69,638,461	(394,285)	(107,236)	508,100	(2,479,834)	2,783,979	69,949,185	5.4
PRIMARY ACCOUNT 324	135,218,459	(1,233,813)	-	-	(18,681,362)	2,576,830	117,880,114	5.1
PRIMARY ACCOUNT 325.1	25,269,074	(263,021)	(9,802)	-	(1,852,279)	1,809,534	24,953,506	4.1
PRIMARY ACCOUNT 325.2 (5 YEAR	2,589,910	(27,709)	-	-	-	90,945	2,653,146	20.0
PRIMARY ACCOUNT 325.3 (7 YEAR	2,614,038	-	-	-	-	612,470	3,226,507	14.3
TOTAL	565,062,903	(9,008,702)	(1,347,509)	508,100	(58,339,822)	18,176,868	515,051,838	
ARO								
Crystal River ARO	(0)	-	-	-	(0)	1,048	1,048	
DECOMMISSIONING - RETAIL	57,812,196	-	-	-	-	-	57,812,196	
DECOMMISSIONING - WHOLESALE	3,773,076	-	-	-	-	-	3,773,076	
TOTAL NUCLEAR	626,648,176	(9,008,702)	(1,347,509)	508,100	(58,339,822)	18,177,916	576,638,159	
OTHER PRODUCTION								
AVON PARK	8,812,148	-	-	-	(852,913)	144,561	8,103,796	5.5
BARTOW	20,024,226	-	-	-	12,421,119	493,352	32,938,697	5.7
BAYBORO	17,566,457	(755,546)	(7,051)	-	(1,236,490)	636,427	16,203,798	3.0
DEBARY	36,218,048	(379,965)	-	-	(2,702,306)	1,348,555	34,484,331	4.3
DEBARY (NEW)	35,277,302	(334,314)	-	-	256,031	4,032,047	39,231,067	3.6
HIGGINS	19,453,969	-	-	-	(1,653,437)	250,545	18,051,077	6.3

PROGRESS ENERGY FLORIDA
SUMMARY OF RESERVE TRANSACTIONS - PER BOOKS
DECEMBER 31, 2006

DESCRIPTION	RESERVE BALANCE 12/31/2005	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2006	DEPRCIATION RATE APPROVED 12/18/98 (1)	
HINES #2	17,947,622	-	-	-	598,768	9,056,185	27,602,575	3.7	
HINES ENERGY COMPLEX	117,571,014	(8,844,069)	(228,408)	11,822,316	(17,294,673)	9,332,662	112,358,842	5.5	
HINES #3	1,149,284	-	-	-	75	10,074,519	11,223,878		
INTERCESSION CITY P1-6	24,475,487	-	-	-	(14,933,087)	959,565	10,501,965	3.7	
INTERCESSION CITY (NEW) P7-10	32,015,171	-	-	-	1,452,798	4,163,181	37,631,150	3.5	
INTERCESSION CITY P11	-	(2,733)	-	-	7,196,899	1,041,528	8,235,694		
INTERCESSION CITY P12-14	19,893,398	-	-	-	9,276,122	4,267,093.61	33,436,614	3.7	
INTERCESSION CITY-SIEMENS	4,156,202	-	-	-	(4,156,202)	-	(0)	4.4	
PORT ST. JOE	-	-	-	-	-		-	-	
RIO PINAR	2,933,680	-	-	-	(336,042)	71,378	2,669,016	6.3	
SUWANNEE	24,250,287	(56,529)	(6,297)	-	(2,070,836)	579,812	22,696,437	4.6	
SYSTEM ASSETS 346.0	-	-	-	-	137,663	11,012	148,676		
SYSTEM ASSETS 346.2 (5 YEAR)	39,318	-	-	-	(17,152)	11,030	33,195	20.0	
SYSTEM ASSETS 346.3 (7 YEAR)	162,764	-	-	-	(120,511)	-	42,253	14.3	
TIGER BAY	44,002,216	(10,967,443)	(4,218)	-	(5,742,021)	2,634,601	29,923,134	6.0	
TURNER	18,960,796	-	-	-	(1,586,074)	538,767	17,913,489	4.8	
UNIVERSITY OF FLORIDA	16,923,169	(149,516)	-	-	8,074	2,510,706	19,292,433	5.8	
TOTAL OTHER PRODUCTION	461,832,556	(21,490,114)	(245,974)	11,822,316	(21,354,194)	52,157,527	482,722,116		
RETAIL RATE DEPRECIATION CREDIT	(250,000,000)	-	-	-	250,000,000	-	0		NOTE 2
TRANSMISSION PLANT									
350.1 TRANSMISSION EASEMENTS	15,438,389	(2,000)	-	-	(1,120,700)	635,201	14,950,890	2.2	
352 STRUCTURES	7,887,176	(1,090,371)	-	-	(118,710)	436,076	7,114,171	2.1	
353 STATION EQUIPMENT	123,820,715	(1,989,522)	(567,064)	(760)	(7,906,564)	8,323,015	121,679,821	2.2	
353.2 ENERGY CONTROL CENTER	33,090,639	-	(1,550)	-	(4,693,328)	929,513	29,325,274	10.9	
354 TOWERS AND FIXTURES	55,682,999	-	(1,621,532)	-	(2,806,102)	1,252,305	52,507,670	2.4	
355 POLES AND FIXTURES	121,938,717	(699,157)	(2,742,293)	-	(12,304,089)	8,425,405	114,618,583	4.0	
356 OVERHEAD CONDUCTOR	127,648,064	(378,521)	(893,754)	293,332	(11,266,555)	5,522,729	120,925,296	3.3	
357 UNDERGROUND CONDUIT	5,539,810	-	-	-	(302,050)	106,024	5,343,785	1.8	
358 UNDERGROUND CONDUCTOR	8,054,304	-	-	-	(522,117)	123,132	7,655,319	1.7	
359 MISCELLANEOUS PLANT EQUI	1,159,194	-	-	-	(149,398)	27,244	1,037,039	1.8	
TOTAL TRANSMISSION PLANT	500,260,008	(4,159,571)	(5,826,193)	292,572	(41,189,612)	25,780,644	475,157,848		
DISTRIBUTION PLANT									
360.1 DISTRIBUTION EASEMENTS	211,615	-	-		(15,452)	6,628	202,791	2.2	
361 STRUCTURES	6,785,054	(45,528)	(227)	-	(176,602)	423,228	6,985,925	2.1	
362 STATION EQUIPMENT	108,273,680	(911,975)	(290,327)	49,070	(209,961)	9,766,915	116,677,401	2.3	
364 POLES AND FIXTURES	218,442,767	(1,080,417)	(384,341)	(430,655)	121,772	17,412,311	234,081,437	4.2	
365 OVERHEAD CONDUCTOR	234,403,798	(4,485,679)	(2,865,666)	-	(17,162,893)	13,162,420	223,051,981	4.7	
366 UNDERGROUND CONDUIT	35,586,455	(213,486)	(111,489)	-	(1,008,082)	3,284,456	37,537,855	2.2	
367 UNDERGROUND CONDUCTOR	127,375,084	(2,865,090)	(255,138)	-	15,146	14,517,379	138,787,381	2.9	
368 LINE TRANSFORMER	206,862,418	(3,920,993)	(817,104)	-	(10,640,168)	14,705,579	206,189,731	4.9	
369.1 OVERHEAD SERVICES	53,615,071	(868,329)	(3,402)	1,444	(20)	2,225,242	54,970,005	4.4	
369.2 UNDERGROUND SERVICES	81,555,826	(9,952,699)	(61,790)	-	275,639	10,217,585	82,034,562	3.3	
370 METERS	50,284,485	(82,445,030)	-	-	22,241	8,638,744	(23,499,560)	3.8	
371 INSTALL ON CUST. PREM.	1,315,091	-	-	-	(30,329)	121,231	1,405,993	6.0	
372 LEASED PROPERTY	54,551	-	-	-	-	-	54,551	4.0	
373 STREET LIGHTING	158,325,381	(2,672,733)	(155,757)	-	(12,302,850)	12,045,957	155,239,997	8.0	

PROGRESS ENERGY FLORIDA
SUMMARY OF RESERVE TRANSACTIONS - PER BOOKS
DECEMBER 31, 2006

DESCRIPTION	RESERVE BALANCE 12/31/2005	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2006	DEPRCIATION RATE APPROVED 12/18/98 (1)
TOTAL DISTRIBUTION PLANT	1,283,091,276	(109,461,959)	(4,945,241)	(380,142)	(41,111,558)	106,527,675	1,233,720,051	
GENERAL PLANT								
390 STRUCTURES	20,027,914	(831,000)	(696,825)	4,735,223	(621,568)	3,509,236	26,122,981	3.7
391 OFFICE EQUIPMENT	-	-	-	-	-		-	14.3
391.1 OFFICE FURNITURE	3,039,178	(807,229)	-	3,122	-	801,061	3,036,132	14.3
391.2 OFFICE EQUIPMENT	24,644	-	-	-	-	11,486	36,130	14.3
391.3 COMPUTERS	3,053,185	(190,831)	-	-	-	515,107	3,377,461	20.0
391.5 DUPLICATING EQUIPMENT	(198,333)	(152,032)	-	2,076	(0)	170,906	(177,384)	14.3
393 STORES EQUIPMENT	43,558	-	-	-	-	-	43,558	14.3
393.1 MOTORIZED HANDLING EQU	2,538,713	(46,555)	-	-	-	423,040	2,915,198	14.3
393.2 STORAGE EQUIPMENT	49,183	(17,254)	-	-	-	44,875	76,804	14.3
393.3 PORTABLE HANDLING EQUIF	(51)	-	-	-	-	557	506	14.3
394 TOOLS, SHOP & GARAGE EQU	225,190	(8,722)	-	-	-	157,829	374,296	14.3
394.1 TOOLS, SHOP & GARAGE EQ	6,291,162	(88)	-	1,000	-	638,969	6,931,043	14.3
394.2 TOOLS, SHOP & GARAGE EQ	1,417,639	(42,725)	-	-	-	612,414	1,987,327	14.3
395.0 LABORATORY EQUIPMENT	1,950	-	-	-	-	1,815	3,766	
395.2 PORTABLE LABORATORY EC	708,845	(267,524)	-	-	-	447,543	888,864	14.3
396 POWER OPERATED EQUIPMEI	2,059,843	-	-	-	-	214,568	2,274,411	5.8
397 COMMUNICATIONS EQUIPMEN	12,937,809	(62,063)	(29,288)	1,802	(133,019)	4,348,051	17,063,293	14.3
397.1 COMMUNICATIONS EQUIPME	21,875,023	(376,804)	(374)	11,975	25,582	599,263	22,134,665	14.3
398.2 MISCELLANEOUS EQUIPMEN	1,342,022	(409,985)	1,479	11,930	-	455,416	1,400,862	14.3
399.1 GENERAL PLT ARO	-	-	-	-	360	36,930	37,290	
TOTAL GENERAL PLANT	75,437,473	(3,212,810)	(725,008)	4,767,128	(728,645)	12,989,064	88,527,202	
TRANSPORTATION EQUIPMENT								
392.1 PASSENGER CARS	818,339	(43,915)	-	-	-	93,084	867,507	8.7
392.2 LIGHT TRUCKS	8,351,369	(194,924)	-	-	-	1,685,509	9,841,954	8.7
392.3 HEAVY TRUCKS	6,994,043	-	-	-	-	707,014	7,701,057	4.8
392.4 SPECIAL EQUIPMENT	33,358,938	(1,043,101)	-	-	-	4,474,132	36,789,969	5.0
392.5 TRAILERS	1,797,777	-	-	-	-	152,941	1,950,718	1.7
392.6 AIRCRAFT (USED)	-	-	-	-	-	-	-	-
392.7 AIRCRAFT (NEW)	(282,195)	-	-	-	-	82,396	(199,799)	5.0
TOTAL TRANSPORTATION EQUIPMENT	51,038,269	(1,281,940)	-	-	-	7,195,076	56,951,405	
TOTAL ELECTRIC PLANT RESERVE	4,161,841,104	(158,659,887)	(13,490,653)	17,496,631	42,653,597	276,048,467	4,325,884,674	
ENERGY CONSERVATION EQUIPMENT								
370.1 METERS	-	-	-	-	-	-	-	
398.1 MISCELLANEOUS	28,851	-	-	-	(11,734)	9,884	27,001	
SUBTOTAL	28,851	-	-	-	(11,734)	9,884	27,001	
ELECTRICAL PLANT ACQUISITION ADJUSTMENT	701,966	-	-	-	280,689	152,657	1,135,311	
INTANGIBLE PLANT	45,692,140	-	-	-	993,425	9,240,324	55,925,889	
INTANGIBLE PLANT - CUST SERV S	58,431,832	-	-	-	46,716	224,139	58,702,686	
SUBTOTAL	104,123,972	-	-	-	1,040,140	9,464,463	114,628,575	
GAS CONVERSION	1,028,672	-	-	-	-	-	1,028,672	

PROGRESS ENERGY FLORIDA
SUMMARY OF RESERVE TRANSACTIONS - PER BOOKS
DECEMBER 31, 2006

DESCRIPTION	RESERVE BALANCE 12/31/2005	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2006	DEPRCIATION RATE APPROVED 12/18/98 (1)
TOTAL ACCOUNT 111 and 119	105,883,460	-	-	-	1,309,095	9,627,003	116,819,558	

NOTE: (1) THE PER BOOKS RESERVE IS COMPUTED UTILIZING DEPRECIATION RATES THAT ARE A BLEND OF RETAIL AND WHOLESALE RATES. COLUMN REFLECTS APPROVED RETAIL RATES. FINANCIAL RATES DID NOT CHANGE FOR 2006, HOWEVER THERE WAS A CHANGE ON THE RETAIL RATES. (See Retail Reserve spreadsheet for new rates)
(2) CREDIT APPROVED IN ORDER NO. PSC-02-0655-AS-EI, DOCKET NO.s 000824-EI,020001-EI.

1080100	ACCUM PROV FOR DEPRECIATION		(4,231,982,370.88)
1080150	FAS 143 ARO ACCUM DEPR		(6,896,036.00)
1080155	FAS 143 COR CONTRA		26,134,909.00
1084000	ACC PROV FOS DISMANT		(144,932,006.75)
108400J	ACC DEPR-NON-RAD DECOM-UNF		(406,957.10)
1084010	ACC DEPN-DEBIT-RETAIL 02		249,999,999.85
10840FR	ACC DEPR-NON-RAD DECOM-R		(57,812,196.36)
10840FW	ACC DEPR-NON-RAD DECOM-W		(3,366,119.00)
1111000	ACCM AMORT-INTANGIBLE PLANT		(105,181,494.27)
1193000	ACC DEPR & AMORT OTHER UTIL		(701,965.66)
	GL Total		(4,275,144,237.17)
		2909	23,442,991.78
		2914	(30,862,664.76)
			(7,419,672.98)
	GL less RWIP		(4,267,724,564.19)
	Total Above		4,267,724,564.19
	Diff		0.00

1080100	ACCUM PROV FOI		(4,100,783,135.55)
1080150	FAS 143 ARO ACC		(6,060,530.76)
1080155	FAS 143 COR CON		26,269,249.17
1084000	ACC PROV FOS DI		(144,863,180.05)
108400J	ACC DEPR-NON-R		(406,957.10)
1084010	ACC DEPN-DEBIT-		-
10840FR	ACC DEPR-NON-R		(57,812,196.36)
10840FW	ACC DEPR-NON-R		(3,366,119.00)
1111000	ACCM AMORT-INT		(115,684,247.56)
1193000	ACC DEPR & AMO		(1,135,310.74)
	GL Total		(4,403,842,427.95)
		2909	55,681,143.46
		2914	(16,819,338.78)
			38,861,804.68
	GL less RWIP		(4,442,704,232.63)
	Total Above		4,442,704,232.63
	Diff		0.00

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