EI 501-08 AR

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

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

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Florida Power Corporation	End of 2008/Q4

Deloitte.

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Florida Power Corporation d/b/a Progress Energy Florida, Inc.
St. Petersburg, Florida

We have audited the balance sheet—regulatory basis of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (the "Company") as of December 31, 2008, and the related statements of income—regulatory basis; retained earnings—regulatory basis; cash flows—regulatory basis; and accumulated other comprehensive income, comprehensive income, and hedging activities—regulatory basis for the year ended December 31, 2008, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

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

As discussed in Note 2 to the financial statements, on January 1, 2008 the Company adopted Financial Accounting Standards Board Staff Position No. FIN 39-1.

In our opinion, such regulatory-basis financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2008, and the results of its operations and its cash flows for the year ended December 31, 2008, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

March 2, 2009

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Florida Power Corporation	02 Year/Period of Report End of 2008/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 299 First Avenue North, St. Petersburg, FL, 33701	
05 Name of Contact Person Cynthia S. Lee	06 Title of Contact Person Manager-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)* 12/31/2008

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Mark Mulhern	03 Signature Mark Mulhern	04 Date Signed *(Mo, Da, Yr)* 04/20/2009
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 Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	12/31/2008	End of 2008/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	12/31/2008	End of 2008/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 Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer	Jeffrey J. Lyash	2,027,619
2			
3	Executive Vice President and Chief Financial Officer	Peter M. Scott III	2,463,213
4			
5	Senior Vice President and Chief Financial Officer	Mark F. Mulhern	2,280,661
6			
7	Chairman	William D. Johnson	6,389,426
8			
9	Executive Vice President	John R. McArthur	1,797,802
10			
11	Senior Vice President	Paula J. Sims	1,247,116
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			
42			
43			
44			

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

Page 104 discloses the compensation of the individual who served as the Chief Executive Officer (CEO) of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) during the year ended December 31, 2008, along with the compensation of both individuals who served as PEF's Chief Financial Officer and the three most highly compensated executive officers other than the CEO and CFO who were serving as executive officers as of December 31, 2008. 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 2008 received by the CEO, CFOs and the other three most highly compensated executives is determined in accordance with Item 402 of Regulation S-K as promulgated by the Securities and Exchange Commission. Progress Energy, Inc.'s (Progress Energy) executive officers serve as officers and/or directors of its various subsidiaries, including PEF. They have multiple responsibilities within and provide various services to Progress Energy and its subsidiaries. The compensation of Progress Energy's executive officers is designed to cover the full range of services they provide to Progress Energy and its subsidiaries. It is not the policy of Progress Energy to allocate compensation paid to its executive officers among the various subsidiaries to which they provide services.

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

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

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 (as of September 1, 2008).

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. Officer retired as of November 17, 2008.

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

See footnote at Line 1 Column C.

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

See footnote at Line 1 Column A.

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

See footnote at Line 1 Column C.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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 J. Lyash, President and CEO	P.O. Box 14042, St. Petersburg, FL 33701
2	John R. McArthur, Executive Vice President	P.O. Box 1551, Raleigh, NC 27602
3	Lloyd M. Yates, President and CEO	P.O. Box 1551, Raleigh, NC 27602
4	William D. Johnson, Chairman	P.O. Box 1551, Raleigh, NC 27602
5	Michael A. Lewis, Senior Vice President	P.O. Box 14042, St. Petersburg, FL 33701
6	Mark F. Mulhern, Chief Financial Officer	P.O. Box 1551, Raleigh, NC 27602
7	Paula J. Sims, Senior Vice President	P.O. Box 1551, Raleigh, NC 27602
8	Peter M. Scott III, Executive Vice President and CFO	P.O. Box 1551, Raleigh, NC 27602
9		
10		
11		
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		
42		
43		
44		
45		
46		
47		
48		

FOOTNOTE DATA

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

President and CEO of Carolina Power and Light Company.

Schedule Page: 105 Line No.: 5 Column: a

Elected to the Board effective January 1, 2008

Schedule Page: 105 Line No.: 6 Column: a

Elected to the Board effective January 1, 2008

Schedule Page: 105 Line No.: 7 Column: a

Elected to the Board effective September 1, 2008

Schedule Page: 105 Line No.: 8 Column: a

Retired from the Board effective September 1, 2008

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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, 2008 there were no important changes or additions to Franchise Rights.

During the quarter ended June 30, 2008 there were no important changes or additions to Franchise Rights.

During the quarter ended September 30, 2008 there were no important changes or additions to Franchise Rights.

During the quarter ended December 31, 2008 there were no important changes or additions to Franchise Rights.

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

2. ACQUISITION OF OWNERSHIP IN OTHER COMPANIES

Effective April 28, 2008, Florida Power Corporation became a 53% owner of SanGroup, LLC, a newly created LLC owned 27.8% by Atlanta Gas Light Company and 19.2% by Florida Power and Light.

Effective May 22, 2008, Florida Power Corporation's ownership percentage of APOG, LLC decreased from 12.5% to 10%.

3. PURCHASE OR SALE OF AN OPERATING UNIT OR SYSTEM

None

4. IMPORTANT LEASEHOLDS

None

5. IMPORTANT EXTENSION OR REDUCTION TO TRANSMISSION OR DISTRIBUTION SYSTEM

None

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

During the quarter ended March 31, 2008, Florida Power Corporation issued $318,000,000 and redeemed $318,000,000 in commercial paper. The weighted average yield issued during the period was 3.492%.

During the quarter ended June 30, 2008, Florida Power Corporation issued $716,400,000 and redeemed $716,400,000 in commercial paper. The weighted average yield issued during the period was 2.944%.

On June 18, 2008, Florida Power Corporation issued $500,000,000 of First Mortgage Bonds, 5.65% Series due 2018 and $1,000,000,000 of First Mortgage Bonds, 6.40% Series due 2038.

During the quarter ended September 30, 2008, Florida Power Corporation did not have any commercial paper outstanding.

During the quarter ended December 31, 2008, Florida Power Corporation issued $977,770,000 and redeemed $607,137,000 in commercial paper. The weighted average yield issued during the period was 3.210%.

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

None

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

Effective March 31, 2008, non-bargaining unit employees received an average 3.75% merit increase. Wages will increase approximately $5 million per year.

Effective December 1, 2008, all bargaining unit employees received a 3.0% wage rate increase in accordance with the Memorandum of Agreement with the International Brotherhood of Electrical Workers. This includes temporary and part-time employees who were active employees or on leave. Wages will increase approximately $3.4 million per year.

9. LEGAL PROCEEDINGS

See Part II, Item 1. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Report on Form 10-Q for the quarter-ended March 31, 2008.

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, 2008.

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, 2008.

See legal proceedings in Part I, Item 1 under "Environmental" in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Report on Form 10-K for the year-ended December 31, 2008.

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

<u>Officer Changes:</u>

Robert A. Glenn, General Counsel	Elected 1/1/2008
Jackie Joyner, Vice President	Elected 1/1/2008
Michael A. Lewis, Sr. Vice President	Elected 1/1/2008
James Scarola, Chief Nuclear Officer and Sr. Vice President	Elected 1/1/2008
Frank A. Schiller, General Counsel	Removed 3/19/2008
Alexander J. Weintraub, Vice President	Elected 4/1/2008
Jocelyn B. Thornton, Vice President	Elected 4/21/2008
Robert J. Duncan II, VP	Elected 07/14/08
Anne M. Huffman, VP	Elected 07/10/08
Mark F. Mulhern, CFO	Elected 09/01/08
Peter M. Scott III, CFO	Removed 09/01/08
Peter M. Scott III, Executive VP	Removed 09/01/08
John R. McArthur, Executive VP	Elected 11/17/08

Director Changes:

Michael A. Lewis	Elected 1/1/2008
Mark F. Mulhern	Elected 1/1/2008
Peter M. Scott III, Director	Removed 9/1/2008
Paula J. Sims, Director	Elected 9/1/2008

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	12/31/2008	End of 2008/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	10,483,943,630	10,060,472,116
3	Construction Work in Progress (107)	200-201	2,075,356,574	1,191,510,032
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		12,559,300,204	11,251,982,148
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,684,684,414	4,540,773,297
6	Net Utility Plant (Enter Total of line 4 less 5)		7,874,615,790	6,711,208,851
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	72,866	5,036,739
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		61,103,723	5,432,526
9	Nuclear Fuel Assemblies in Reactor (120.3)		104,936,776	104,048,587
10	Spent Nuclear Fuel (120.4)		0	41,325,520
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	60,032,977	76,991,397
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		106,080,388	78,851,975
14	Net Utility Plant (Enter Total of lines 6 and 13)		7,980,696,178	6,790,060,826
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		10,324,516	10,324,516
19	(Less) Accum. Prov. for Depr. and Amort. (122)		5,060,038	4,346,753
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	47,167,463	28,663,433
24	Other Investments (124)		2,487,469	1,537,870
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		446,427,818	619,964,706
29	Special Funds (Non Major Only) (129)		0	220,570,036
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		678,014	99,419,541
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		502,025,242	976,133,349
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		17,203,736	17,473,015
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	3,580,742
39	Notes Receivable (141)		156,823	26,125
40	Customer Accounts Receivable (142)		287,645,442	278,710,573
41	Other Accounts Receivable (143)		22,774,032	24,045,585
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		10,863,895	10,406,159
43	Notes Receivable from Associated Companies (145)		0	148,792,311
44	Accounts Receivable from Assoc. Companies (146)		15,443,813	8,435,554
45	Fuel Stock (151)	227	326,907,773	245,349,474
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	227,182,263	201,489,836
49	Merchandise (155)	227	505,165	674,288
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	76,702,015	31,568,873

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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		47,167,463	28,663,433
54	Stores Expense Undistributed (163)	227	22,069,958	33,546,843
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)		8,240,691	3,615,876
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		1,094,409	0
60	Rents Receivable (172)		325,537	176,219
61	Accrued Utility Revenues (173)		62,050,535	58,931,935
62	Miscellaneous Current and Accrued Assets (174)		335,099,614	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)		9,331,402	182,630,791
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		678,014	99,419,541
67	Total Current and Accrued Assets (Lines 34 through 66)		1,354,023,836	1,100,558,907
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		42,801,460	28,018,345
70	Extraordinary Property Losses (182.1)	230	13,668,566	15,658,702
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	1,650,975,219	282,027,360
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,569,978	2,401,428
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	22,529,290	9,063,123
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)		20,969,828	24,853,429
82	Accumulated Deferred Income Taxes (190)	234	642,773,374	458,534,900
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,397,287,715	820,557,287
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		12,234,032,971	9,687,310,369

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 110 Line No.: 72 Column: d

The 12/31/2007 FERC Form 1 balance will not agree to the 2007 FERC Form 1 report due to FSP FIN 39-1 adoption in the CY as a retrospective adjustment to PY balances.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	end of 2008/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	762,002,026	754,871,665
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	2,283,689,225	1,900,565,502
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	5,490	-60
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)	-601,322	-8,365,798
16	Total Proprietary Capital (lines 2 through 15)		3,433,028,549	3,035,004,439
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,040,865,000	2,620,865,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	150,000,000	601,900,002
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		8,971,356	3,554,901
24	Total Long-Term Debt (lines 18 through 23)		4,181,893,644	3,219,210,101
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		215,895,932	223,554,534
27	Accumulated Provision for Property Insurance (228.1)		138,840,416	63,452,978
28	Accumulated Provision for Injuries and Damages (228.2)		19,648,095	17,687,819
29	Accumulated Provision for Pensions and Benefits (228.3)		457,509,498	263,008,776
30	Accumulated Miscellaneous Operating Provisions (228.4)		108,589,511	107,974,543
31	Accumulated Provision for Rate Refunds (229)		1,569,227	1,887,590
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		209,087,489	9,323,620
34	Asset Retirement Obligations (230)		348,978,715	314,585,846
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,500,118,883	1,001,475,706
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		370,633,000	0
38	Accounts Payable (232)		497,988,319	450,787,742
39	Notes Payable to Associated Companies (233)		72,530,642	0
40	Accounts Payable to Associated Companies (234)		55,214,051	87,440,072
41	Customer Deposits (235)		199,623,363	184,625,135
42	Taxes Accrued (236)	262-263	-27,105,282	-21,197,682
43	Interest Accrued (237)		51,185,725	57,052,531
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Florida Power Corporation	(1) [x] An Original (2) [ ] A Rresubmission	12/31/2008	end of 2008/Q4

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)		15,594,322	22,825,452
48	Miscellaneous Current and Accrued Liabilities (242)		84,131,866	63,172,493
49	Obligations Under Capital Leases-Current (243)		7,659,787	7,124,768
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		589,633,299	47,603,424
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		209,087,489	9,323,620
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,708,001,603	890,110,315
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,581,949	1,110,325
57	Accumulated Deferred Investment Tax Credits (255)	266-267	11,506,508	17,446,508
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	42,341,531	37,281,767
60	Other Regulatory Liabilities (254)	278	154,333,815	668,219,666
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	4,083,000	6,186,000
63	Accum. Deferred Income Taxes-Other Property (282)		547,273,147	441,093,000
64	Accum. Deferred Income Taxes-Other (283)		649,870,342	370,172,542
65	Total Deferred Credits (lines 56 through 64)		1,410,990,292	1,541,509,808
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		12,234,032,971	9,687,310,369

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 112 Line No.: 60 Column: d

The 12/31/2007 FERC Form 1 balance will not agree to the 2007 FERC Form 1 report due to FSP FIN 39-1 adoption in the CY as a retrospective adjustment to PY balances.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	4,730,890,488	4,692,523,332		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,540,901,717	3,243,675,914		
5	Maintenance Expenses (402)	320-323	180,419,428	165,685,317		
6	Depreciation Expense (403)	336-337	301,087,762	286,866,834		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	354,972	354,972		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	3,109,079	8,253,968		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-411,097	-411,097		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)			75,226,252		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		187,315,450	136,291,429		
13	(Less) Regulatory Credits (407.4)		486,752,213	126,981,192		
14	Taxes Other Than Income Taxes (408.1)	262-263	309,321,940	308,922,720		
15	Income Taxes - Federal (409.1)	262-263	36,540,063	155,587,614		
16	- Other (409.1)	262-263	11,486,179	28,773,090		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,042,755,413	298,702,301		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	906,458,818	337,343,771		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,940,000	-5,940,000		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		17,222,582	16,329,546		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,230,952,457	4,253,993,897		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		499,938,031	438,529,435		

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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
4,730,890,488	4,692,523,332					2
						3
3,540,901,717	3,243,675,914					4
180,419,428	165,685,317					5
301,087,762	286,866,834					6
354,972	354,972					7
3,109,079	8,253,968					8
-411,097	-411,097					9
	75,226,252					10
						11
187,315,450	136,291,429					12
486,752,213	126,981,192					13
309,321,940	308,922,720					14
36,540,063	155,587,614					15
11,486,179	28,773,090					16
1,042,755,413	298,702,301					17
906,458,818	337,343,771					18
-5,940,000	-5,940,000					19
						20
						21
						22
						23
17,222,582	16,329,546					24
4,230,952,457	4,253,993,897					25
499,938,031	438,529,435					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	12/31/2008	End of 2008/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)		499,938,031	438,529,435		
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)		18,475,162	22,460,428		
34	(Less) Expenses of Nonutility Operations (417.1)		11,336,227	15,756,854		
35	Nonoperating Rental Income (418)		-519,341	-430,005		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	5,490	-60		
37	Interest and Dividend Income (419)		6,355,326	7,384,528		
38	Allowance for Other Funds Used During Construction (419.1)		94,850,807	40,962,057		
39	Miscellaneous Nonoperating Income (421)		3,218,619	2,975,725		
40	Gain on Disposition of Property (421.1)		5,222,570	4,977,039		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		116,272,406	62,572,858		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			299		
44	Miscellaneous Amortization (425)	340	822,181	116,050		
45	Donations (426.1)	340	7,752,585	4,400,283		
46	Life Insurance (426.2)		8,665,921	-2,507,651		
47	Penalties (426.3)		-1,355,072	2,111,225		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		3,035,620	4,097,876		
49	Other Deductions (426.5)		1,457,358	1,162,301		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		20,378,593	9,380,383		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	98,729	103,766		
53	Income Taxes-Federal (409.2)	262-263	2,458,048	4,183,909		
54	Income Taxes-Other (409.2)	262-263	405,656	-173,270		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,127	592,324		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	277,579	241,072		
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)		2,685,981	4,465,657		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		93,207,832	48,726,818		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		211,549,646	150,747,234		
63	Amort. of Debt Disc. and Expense (428)		5,111,017	4,364,116		
64	Amortization of Loss on Reaquired Debt (428.1)		4,142,098	2,167,686		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340	1,247,195	2,199,543		
68	Other Interest Expense (431)	340	14,314,870	22,663,205		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		28,237,751	12,216,397		
70	Net Interest Charges (Total of lines 62 thru 69)		208,127,075	169,925,387		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		385,018,788	317,330,866		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		385,018,788	317,330,866		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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		1,900,565,502	1,588,449,439
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Unrealized tax benefit/expense		-377,715	(3,190,052)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-377,715	(3,190,052)
10	FIN 48 Cumulative Impact			(512,951)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(512,951)
16	Balance Transferred from Income (Account 433 less Account 418.1)		385,013,298	317,330,926
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock Dividends Declared		-1,511,860	(1,511,860)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,511,860	(1,511,860)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock Dividends Declared			
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,283,689,225	1,900,565,502
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,283,689,225	1,900,565,502
	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)		5,490	(60)
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		5,490	(60)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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)	385,018,788	317,330,866
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	301,801,047	287,520,679
5	Amortization of Limited and Electric Plant, Nuclear Fuel, Load Mgmt	11,280,378	17,287,043
6	Amortization of Debt Premium, expense and loss on acquisition	4,838,154	4,726,220
7	Other: (Gain) Loss on sale of assets, Other Adjustments to Net Income	39,625,894	76,209,698
8	Deferred Income Taxes (Net)	136,020,143	-38,649,772
9	Investment Tax Credit Adjustment (Net)	-5,940,000	-5,940,000
10	Net (Increase) Decrease in Receivables	-32,917,365	-19,979,624
11	Net (Increase) Decrease in Inventory	-95,474,408	-34,514,719
12	Net (Increase) Decrease in Allowances Inventory	-45,133,142	-29,626,172
13	Net Increase (Decrease) in Payables and Accrued Expenses	34,231,151	61,256,660
14	Net (Increase) Decrease in Other Regulatory Assets	-119,979,439	80,781,173
15	Net Increase (Decrease) in Other Regulatory Liabilities	-176,230,548	59,061,019
16	(Less) Allowance for Other Funds Used During Construction	94,850,807	40,962,057
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote): Change in Current Assets	-327,160,502	72,422,964
19	Change in Other, Net	35,482,637	-7,584,178
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	50,611,981	799,339,800
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,647,324,254	-1,255,440,625
27	Gross Additions to Nuclear Fuel	-42,518,434	-43,883,010
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-5,946,120	-3,283,219
30	(Less) Allowance for Other Funds Used During Construction	-94,850,807	-40,962,057
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,600,938,001	-1,261,644,797
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	11,958,135	7,415,214
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-1,281,158	-149,116,150
40	Contributions and Advances from Assoc. and Subsidiary Companies	148,850,125	
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-781,612,508	-639,764,372
45	Proceeds from Sales of Investment Securities (a)	783,776,944	639,764,372

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote): Company Owned Life Insurance		974,998
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,439,246,463	-1,402,370,735
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,475,346,736	739,269,819
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote): Increase in Intercompany Notes	72,276,387	
65			
66	Net Increase in Short-Term Debt (c)	370,633,000	
67	Other (provide details in footnote):		71,051
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,918,256,123	739,340,870
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-531,905,994	-88,600,004
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote): Decrease in Intercompany Notes		-46,794,314
77			
78	Net Decrease in Short-Term Debt (c)		
79	Other	-53,809	
80	Dividends on Preferred Stock	-1,511,859	-1,511,859
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	1,384,784,461	602,434,693
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-3,850,021	-596,242
87			
88	Cash and Cash Equivalents at Beginning of Period	21,053,757	21,649,999
89			
90	Cash and Cash Equivalents at End of period	17,203,736	21,053,757

Schedule Page: 120 Line No.: 15 Column: c

Line 15, column (c) - $52,475,571 was reclassified in the prior year from Net Increase in Other Regulatory Liabilities to Change in Other, Net for consistency with current year presentation.

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

Change in Other, Net includes the following:

Change in Other Assets and Deferred Debits:	$(13,752,192)
Proceeds from termination of interest rate hedge:	14,464,149
Other:	(146,952)
Change in Other Liabilities and Deferred Credits:	34,917,632

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

Line 19, column (c) - $52,475,571 was reclassified in the prior year from Net Increase in Other Regulatory Liabilities to Change in Other, Net for consistency with current year presentation.

Change in Other, Net includes the following:

Other:	$753,760
Change in Other Assets and Deferred Debits:	325,084
Proceeds from termination of interest rate hedge:	(13,873,320)
Change in Pensions	(15,096,684)
Change in Other Liabilities and Deferred Credits:	20,306,982

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

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

OTHER DISCLOSURES

Cash payments for interest and income taxes for 2008 were approximately $205 million and $52 million, respectively.

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

COMBINED NOTES TO FINANCIAL STATEMENTS

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

1. <u>ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES</u>

A. ORGANIZATION

PROGRESS ENERGY, INC.

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

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

See Note 19 for further information about our segments.

PEC

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

PEF

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

B. BASIS OF PRESENTATION

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy, and as such their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements. Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in minority interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for minority interest are reported on a net of tax basis if the underlying subsidiary is structured as a taxable entity.

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies, 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 12 for more information about our investments.

Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by Statement of Financial Accounting Standards (SFAS) No. 71, “Accounting for the Effects of Certain Types of Regulation” (SFAS No. 71), which provides that profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of the sales price through the ratemaking process is probable.

Our presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under SFAS No. 95, “Statement of Cash Flows.”

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 2007 and 2006 have been reclassified to conform to the 2008 presentation.

RESTATEMENT

During the preparation of our December 31, 2008 financial statements, we identified an error in accounting for our and PEC’s unbilled revenue. The cumulative impact of this error on beginning retained earnings and common stock equity at December 31, 2005, was a decrease of $27 million.

PROGRESS ENERGY

The following table reflects the effects of the restatement on the Consolidated Statements of Changes in Common Stock Equity as of December 31, 2006:

(in millions)	As Previously Reported	Restatement Adjustments	As Restated
Retained earnings	$2,594	$(27)	$2,567
Total common stock equity	8,286	(27)	8,259

The following table reflects the effects of the restatement on the Consolidated Balance Sheet and Consolidated Statement of Changes in Common Stock Equity as of December 31, 2007:

(in millions)	As Previously Reported	Restatement Adjustments	As Restated
Receivables, net	$1,167	$(45)	$1,122
Prepayments and other current assets	183	18	201
Total current assets	2,829	(27)	2,802
Total assets	26,365	(27)	26,338
Retained earnings	2,465	(27)	2,438
Total common stock equity	8,422	(27)	8,395
Total capitalization	17,336	(27)	17,309
Total capitalization and liabilities	26,365	(27)	26,338

Our net income for the years ended December 31, 2008, 2007 and 2006 was not materially impacted by this error; accordingly no income adjustments have been recorded.

PEC

The following table reflects the effects of the restatement on the PEC Consolidated Statements of Changes in Common Stock Equity as of December 31, 2006:

(in millions)	As Previously Reported	Restatement Adjustments	As Restated
Retained earnings	$1,431	$(27)	$1,404
Total common stock equity	3,390	(27)	3,363

The following table reflects the effects of the restatement on the PEC Consolidated Balance Sheet and Consolidated Statement of Changes in Common Stock Equity as of December 31, 2007:

(in millions)	As Previously Reported	Restatement Adjustments	As Restated
Receivables, net	$491	$(45)	$446
Prepayments and other current assets	42	18	60
Total current assets	1,266	(27)	1,239
Total assets	11,982	(27)	11,955
Retained earnings	1,772	(27)	1,745
Total common stock equity	3,779	(27)	3,752
Total capitalization	7,021	(27)	6,994
Total capitalization and liabilities	11,982	(27)	11,955

PEC's net income for the years ended December 31, 2008, 2007 and 2006 was not materially impacted by this error; accordingly no income adjustments have been recorded.

C. CONSOLIDATION OF VARIABLE INTEREST ENTITIES

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities (VIEs) for which we are the primary beneficiary in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" (FIN 46R).

In general, we determine whether we are the primary beneficiary of a VIE through a qualitative analysis of risk which identifies which variable interest holder absorbs the majority of the financial risk and variability of the VIE. In performing this analysis, we consider all relevant facts and circumstances, including: the design and activities of the VIE, the terms of the contracts the VIE has entered into, the nature of the VIE's variable interests issued and how they were negotiated with or marketed to potential investors, and which parties participated significantly in the design or redesign of the entity. If the qualitative analysis is inconclusive, a specific quantitative analysis is performed in accordance with FIN 46R.

In December 2008, the FASB issued FASB Staff Position (FSP) No. FAS 140-4 and FIN 46R-8, "Disclosures by Public Entities (Enterprises) About Transfers of Financial Assets and Interests in Variable Interest Entities," which is effective for Progress Energy on December 31, 2008. This FSP amended the disclosure requirements of FIN 46R. The Progress Registrants' disclosures required by the FSP are presented below. For purposes of these disclosures, the maximum loss amounts represent the maximum exposure that would be absorbed by the Progress Registrants in the event that all of the assets of the VIE are deemed worthless, including any additional costs that the Progress Registrants would incur.

PROGRESS ENERGY

In addition to the variable interests listed below for PEC and PEF, Progress Energy, through its subsidiary Progress Fuels Corporation (Progress Fuels), is the primary beneficiary of, and consolidates, Ceredo Synfuel, LLC (Ceredo), a coal-based solid synthetic fuels production facility that qualified for federal tax credits under Section 45K of the Internal Revenue Code (the Code). In March 2007, we disposed of our 100 percent ownership interest in Ceredo to a third-party buyer. Ceredo ceased operations upon expiration of the synthetic fuels tax credit program at the end of 2007. Our variable interests in Ceredo are comprised of an agreement to operate the Ceredo facility on behalf of the buyer through December 2007 and certain legal and tax indemnifications provided to the buyer. We performed a qualitative analysis to determine the primary beneficiary of Ceredo. The primary factors in the analysis were the estimated levels of production of qualifying synthetic fuels in 2007, the final value of the related 2007 synthetic fuels tax credits, the likelihood of a full or partial phase-out of the 2007 synthetic fuels tax credits due to high oil prices, our exposure to certain variable costs under the facility operating agreement and exposure from indemnifications provided to the buyer. There were no changes to our assessment of the primary beneficiary during 2007 or 2008. No financial or other support has been provided to Ceredo during the periods presented. At December 31, 2008, we had no assets and $20 million of liabilities related to the legal and tax indemnifications provided to the buyer included in other liabilities and deferred credits in the Progress Energy Consolidated Balance Sheets. The ultimate resolution of the indemnifications could result in adjustments to the loss on disposal in future periods. The creditors of Ceredo do not have recourse to the general credit of Progress Energy. See Note 3J for additional information on the disposal of Ceredo and Note 22C for a general discussion of guarantees.

PEC

VARIABLE INTEREST ENTITIES FOR WHICH PEC IS THE PRIMARY BENEFICIARY

PEC is the primary beneficiary of, and consolidates, two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Code. PEC's variable interests are debt and equity investments in the two VIEs. PEC performed quantitative analyses to determine the primary beneficiaries of the two VIEs. The primary factors in the analyses were the estimated economic lives of the partnerships and their net cash flow projections, estimates of available tax credits, and the likelihood of default on debt and other commitments. There were no changes to PEC's assessment of the primary beneficiary during 2006 through 2008. No financial or other support has been provided to the VIEs during the periods presented. At December 31, 2008, PEC had assets of $40 million, substantially all of which was reflected in miscellaneous other property and investment, and $16 million in long-term debt, $7 million in other liabilities and deferred credits and $4 million in accounts payable in the PEC Consolidated Balance Sheets related to the two VIEs. The assets of the two VIEs are collateral for, and can only be used to settle, their obligations. The creditors of these VIEs do not have recourse to the general credit of PEC and there are no other arrangements that could expose PEC to losses.

OTHER VARIABLE INTERESTS

PEC has an equity investment in, and consolidates, one limited partnership investment fund that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. The investment fund accounts for the 17 partnerships on the equity method of accounting. PEC also has an interest in one power plant resulting from long-term power purchase contracts. PEC's only significant exposure to variability from the power purchase contracts results from fluctuations in the market price of fuel used by the entity's plants to produce the power purchased by PEC. We are able to recover these fuel costs under PEC's fuel clause. Total purchases from this counterparty were $44 million, $39 million and $45 million in 2008, 2007 and 2006, respectively. The generation capacity of the entity's power plant is approximately 847 megawatts (MW). PEC has requested the necessary information to determine if the investment fund's 17 partnerships and the power plant owner are VIEs or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC, and, accordingly, PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the 17 partnerships and the power plant. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the power plant and the investment fund consolidating the 17 partnerships would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparties, the impact cannot be determined at this time.

PEF

The following information is provided for PEF's significant variable interests in VIEs for which PEF is not the primary beneficiary:

PEF has a prepayment clause in a building capital lease with a special purpose entity that is a VIE. In accordance with the lease agreement, PEF is not required to make any lease payments over the last 20 years of the lease, during which period $51 million of rental expense will be recorded in the PEF Statements of Income. The prepayment clause is PEF's only variable interest in the VIE and, therefore, PEF's exposure to loss primarily relates to the recovery of the prepayments through future use of the rental property. PEF performed qualitative and quantitative analyses and concluded that it is not the primary beneficiary of the VIE. The primary factors in the analyses were the lease term, the fact that the lease payments are not variable interests, the likelihood of construction and casualty risks to the building and the existence of insurance to offset those risks, and the estimated fair value of the building at the end of the lease term. There were no changes to PEF's assessment of the primary beneficiary during 2006 through 2008. No financial or other support has been provided to the VIE during the periods presented. At December 31, 2008, PEF had a $4 million prepayment included in prepayments and other current assets on the PEF Balance Sheets. No liabilities associated with the prepayment clause were recorded. The aggregate maximum exposure to loss at December 31, 2008, is $51 million, which represents the loss if the maximum prepayment of rent at the end of year 20 was not recovered through future use of the rental property or from third-party insurers at that time.

PEF has a residual value guarantee in an operating railcar lease agreement with a special purpose entity that is a VIE. The lease agreement has an early termination clause that permits PEF to terminate the lease in certain circumstances. If PEF terminates the lease in accordance with the agreement, it must sell the railcars and remit the proceeds to the lessor plus any amount for which the residual value guarantee exceeds the realized value of the equipment. The residual value guarantee is PEF's primary variable interest in the VIE and, therefore, PEF's exposure to loss is from the potential decrease in the fair value of the railcars. PEF performed qualitative and quantitative analyses and concluded that it is not the primary beneficiary of the VIE. The primary factors in the analyses were the terms of the lease, the probability of exercising the early termination clause, and the estimated fair value of the railcars. There were no changes to PEF's assessment of the primary beneficiary during 2006 through 2008. No financial or other support has been provided to the VIE during the periods presented. No liabilities associated with the residual value guarantee were recorded as of December 31, 2008, because the early termination clause was not exercised. The aggregate maximum exposure to loss at December 31, 2008, is $18 million, which represents the maximum loss if the early termination clause were exercised in 2009 and the related railcars were deemed worthless.

D. SIGNIFICANT ACCOUNTING POLICIES

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

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

FUEL COST DEFERRALS

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

EXCISE TAXES

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for sales and use tax on a net basis and gross receipts tax, franchise taxes and other excise taxes on a gross basis. The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income in the statements of income for the years ended December 31 were as follows:

(in millions)	**2008**	2007	2006
Progress Energy	**$295**	$299	$293
PEC	**102**	99	94
PEF	**193**	200	199

STOCK-BASED COMPENSATION

As discussed in Note 9B, we account for stock-based compensation utilizing the modified prospective transition method per the fair value recognition provisions of SFAS No. 123R, "Share-Based Payment" (SFAS No. 123R).

RELATED PARTY TRANSACTIONS

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

UTILITY PLANT

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

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

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

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

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

ASSET RETIREMENT OBLIGATIONS

We account for AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, in accordance with SFAS No. 143. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability. Accretion expense is included in depreciation, amortization and accretion in the Consolidated Statements of Income. The adoption of SFAS No. 143 and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143" (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.

CASH AND CASH EQUIVALENTS

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

INVENTORY

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

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to 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.

NUCLEAR COST DEFERRALS

PEF accounts for costs incurred in connection with the proposed nuclear expansion in Florida in accordance with FPSC regulations, which establish an alternative cost-recovery mechanism. PEF is allowed to accelerate the recovery of prudently incurred siting, preconstruction costs, AFUDC and incremental operation and maintenance expenses resulting from the siting, licensing, design and construction of a nuclear plant through PEF's capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through PEF's fuel cost-recovery clause. Unrecovered nuclear costs eligible for accelerated recovery are deferred and recorded as regulatory assets in the Consolidated Balance Sheets and are amortized in the period the costs are collected from customers.

GOODWILL AND INTANGIBLE ASSETS

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

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

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

INCOME TAXES

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

Deferred income taxes have been provided for temporary differences. These occur when there are differences between the book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. Credits for the production and sale of synthetic fuels are deferred credits to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns, and are included in income tax expense (benefit) of discontinued operations in the Consolidated Statements of Income. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority, including resolutions of any related appeals or litigation processes, based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount of the tax benefit that, in our judgment, is greater than 50 percent likely to be realized. Interest expense on tax deficiencies and uncertain tax positions is included in net interest charges, and tax penalties are included in other, net in 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 on 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. In accordance with FSP No. FIN 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts," (FSP FIN 39-1), we elect not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. Certain economic derivative instruments receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. See Note 17 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies in accordance with SFAS No. 5, "Accounting for Contingencies" (SFAS No. 5). Under SFAS No. 5, contingent losses such as unfavorable results of litigation are recorded when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. Unless otherwise required by GAAP, we do not accrue legal fees when a contingent loss is initially recorded, but rather when the legal services are actually provided.

As discussed in Note 21, we accrue environmental remediation liabilities when the criteria for SFAS No. 5 have been met. We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable or on actual receipt of recovery. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

We account for impairment of long-lived assets in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). We review the recoverability of long-lived tangible and intangible assets whenever impairment indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an impairment indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

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

2. NEW ACCOUNTING STANDARDS

Refer to Note 1C for information regarding our implementation of FIN 46R-8, "Disclosures by Public Entities (Enterprises) About Transfers of Financial Assets and Interests in Variable Interest Entities," which is effective for Progress Energy on December 31, 2008, and which amended the disclosure requirements of FIN 46R.

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

On January 1, 2008, we implemented FSP FIN 39-1, which allows a reporting entity to make an accounting election whether or not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. Prior to the adoption of FSP FIN 39-1, we and the Utilities offset fair value amounts recognized for derivative instruments under master netting arrangements. FSP FIN 39-1 was implemented as a retrospective change in accounting principle and upon adoption, Progress Energy, PEC and PEF discontinued the offset of fair value amounts for such derivatives. The adoption of FSP FIN 39-1 did not have a material impact on our or the Utilities' financial position or results of operations.

Fair Value Measurements - Adoption of FASB Statements Nos. 157 and 159

Refer to Note 13B for information regarding our first quarter 2008 implementation of SFAS No. 157, "Fair Value Measurements" (SFAS No. 157).

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

SFAS No. 141R, "Business Combinations"

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

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

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

SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133"

In March 2008, the FASB issued SFAS Statement No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" (SFAS No. 161), which requires entities to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 is effective for us on January 1, 2009, and encourages, but does not require, comparative disclosures for earlier periods at initial adoption. The adoption of SFAS No. 161 will change certain disclosures in the notes to the financial statements, but will have no impact on our or the Utilities' financial position or results of operations.

FSP No. SFAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets"

In December 2008, the FASB issued FSP No. SFAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets" (FSP SFAS 132R-1), which requires additional disclosures on the investment allocation decision making process, the fair value of each major category of plan assets and the inputs and valuation techniques used to remeasure the fair value of plan assets. FSP SFAS 132R-1 is effective for us on December 31, 2009. The adoption of FSP SFAS 132R-1 will change certain disclosures in the notes to the financial statements, but will have no impact on our or the Utilities' financial position or results of operations.

3. DIVESTITURES

A. TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

On March 7, 2008, we sold coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. The coal terminals had a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale were used for general corporate purposes. During the year ended December 31, 2008, we recorded an after-tax gain of $42 million on the sale of these assets. The accompanying consolidated financial statements reflect the operations of Terminals as discontinued operations.

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

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 was reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. This charge represented 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 were located.

Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for each of the years ended December 31, 2007 and 2006 was $1 million. We ceased recording depreciation upon classification of the assets as discontinued operations in November 2007. After-tax depreciation expense during the years ended December 31, 2007 and 2006 was $2 million and $4 million, respectively.

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

(in millions)	**2008**	2007	2006
Revenues	**$17**	$1,126	$847
Earnings (loss) before income taxes and minority interest	**$8**	$2	$(179)
Income tax benefit, including tax credits	**12**	64	135
Minority interest share of (earnings) losses	**(1)**	17	7
Net earnings (loss) from discontinued operations	**19**	83	(37)
Gain on disposal of discontinued operations, including income tax expense of $7	**42**	–	–
Earnings (loss) from discontinued operations	**$61**	$83	$(37)

B. COAL MINING BUSINESSES

On March 7, 2008, we sold the remaining operations of Progress Fuels subsidiaries engaged in the coal mining business (Coal Mining) for gross cash proceeds of $23 million. Proceeds from the sale were used for general corporate purposes. These assets included Powell Mountain Coal Co. and Dulcimer Land Co., which consisted of approximately 30,000 acres in Lee County, Va., and Harlan County, Ky. As a result of the sale, during the year ended December 31, 2008, we recorded an after-tax gain of $7 million on the sale of these assets.

On May 1, 2006, we sold certain net assets of three of our coal mining businesses 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 accompanying consolidated financial statements reflect the coal mining operations as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of the coal mines, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for each of the years ended December 31, 2007 and 2006 was $1 million. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

(in millions)	2008	2007	2006
Revenues	$2	$28	$84
Loss before income taxes	$(13)	$(17)	$(11)
Income tax benefit	4	6	7
Net loss from discontinued operations	(9)	(11)	(4)
Gain (loss) on disposal of discontinued operations, including income tax (expense) benefit of $(2) and $16	7	–	(10)
Loss from discontinued operations	$(2)	$(11)	$(14)

C. CCO – GEORGIA OPERATIONS

On March 9, 2007, our subsidiary, Progress Energy Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. Assets divested included approximately 1,900 MW of gas-fired generation assets in Georgia. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated after-tax loss of $226 million in December 2006. Based on the terms of the final agreement and post-closing adjustments, during the years ended December 31, 2008 and 2007, we incurred an additional $2 million after-tax in losses and reversed $18 million after-tax of the impairment recorded in 2006, respectively.

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

The accompanying consolidated financial statements reflect the operations of CCO as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007 and 2006 was $11 million and $36 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. After-tax depreciation expense was $14 million for the year ended December 31, 2006. Results of discontinued operations for CCO for the years ended December 31 were as follows:

(in millions)	2008	2007	2006
Revenues	$–	$407	$754
Loss before income taxes	$(5)	$(449)	$(92)
Income tax benefit	2	166	35
Net loss from discontinued operations	(3)	(283)	(57)
(Loss) gain on disposal of discontinued operations, including income tax (expense) benefit of $(2), $7 and $123, respectively	(2)	18	(226)
Loss from discontinued operations	$(5)	$(265)	$(283)

D. NATURAL GAS DRILLING AND PRODUCTION

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

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

The accompanying consolidated financial statements reflect the operations of Gas as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated was $13 million for the year ended December 31, 2006. We ceased recording depreciation upon classification of the assets as discontinued operations in July 2006. After-tax depreciation expense was $16 million for the year ended December 31, 2006. Results of discontinued operations for Gas for the years ended December 31 were as follows:

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

E. CCO – DESOTO AND ROWAN GENERATION FACILITIES

On May 8, 2006, we entered into definitive agreements to divest of two subsidiaries of PVI, DeSoto County Generating Co., LLC (DeSoto) and Rowan County Power, LLC (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. DeSoto owned a 320-MW dual-fuel combustion turbine electric generation facility in DeSoto County, Fla., and Rowan owned a 925-MW dual-fuel combined cycle and combustion turbine electric generation facility in Rowan County, N.C. We used the proceeds from the sales to reduce debt and for other corporate purposes.

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

The accompanying consolidated financial statements reflect the operations of DeSoto and Rowan as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated was $6 million for the year ended December 31, 2006. We ceased recording depreciation upon classification of the assets as discontinued operations in May 2006. After-tax depreciation expense during the year ended December 31, 2006, was $3 million. Results of discontinued operations for DeSoto and Rowan for the year ended December 31 were as follows:

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

F. PROGRESS TELECOM, LLC

On March 20, 2006, we completed the sale of Progress Telecom, LLC (PT LLC) to Level 3 Communications, Inc. We received gross proceeds comprised of cash of $69 million and approximately 20 million shares of Level 3 Communications, Inc. 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 Communications, Inc. stock in 2006.

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

The accompanying consolidated financial statements reflect the operations of PT LLC as discontinued operations. Results of discontinued operations for PT LLC for the year ended December 31 were as follows:

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

In connection with the sale, PEC and PEF provided indemnification against costs associated with certain asset performances to Level 3 Communications, Inc. 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.

G. DIXIE FUELS AND OTHER FUELS BUSINESS

On March 1, 2006, we sold Progress Fuels' 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units. Dixie Fuels primarily transported coal from the lower Mississippi River to Progress Energy's Crystal River facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels during the year ended December 31, 2006. During the years ended December 31, 2008 and 2007, we recorded additional gains of $1 million and $2 million, respectively, primarily related to the expiration of indemnifications.

The accompanying consolidated financial statements reflect Dixie Fuels and the other fuels business as discontinued operations. Results of discontinued operations for Dixie Fuels and other fuels businesses for the years ended December 31 were as follows:

(in millions)	**2008**	2007	2006
Revenues	$–	$–	$20
Earnings before income taxes	$–	$–	$11
Income tax expense	–	–	(4)
Net earnings from discontinued operations	–	–	7
Gain on disposal of discontinued operations, including income tax benefit (expense) of $1, $(1) and $(1), respectively	1	2	2
Earnings from discontinued operations	**$1**	$2	$9

H. PROGRESS RAIL

We completed the sale of Progress Rail Services Corporation during the year ended December 31, 2005. As a result of certain legal, tax and environmental indemnifications provided by Progress Fuels and Progress Energy, we continue to record adjustments to the loss on sale. During the year ended December 31, 2008, we recorded an after-tax gain on disposal of $2 million. During the year ended December 31, 2006, we recorded an after-tax loss on disposal of $6 million. The ultimate resolution of these matters could result in additional adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

I. NET ASSETS TO BE DIVESTED

At December 31, 2007, the assets and liabilities of Terminals and the remaining assets and liabilities of Coal Mining were included in net assets to be divested. The major balance sheet classes included in assets and liabilities to be divested in the Consolidated Balance Sheets were as follows:

(in millions)	December 31, 2007
Inventory	$6
Other current assets	2
Property, plant and equipment, net	38
Other assets	6
Assets to be divested	$52
Accrued expenses	$3
Long-term liabilities	5
Liabilities to be divested	$8

J. CEREDO SYNTHETIC FUELS INTERESTS

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

During the year ended December 31, 2008, we recognized previously deferred gains on disposal of $5 million based on the final value of the 2007 Section 29/45K tax credits. The operations of Ceredo ceased as of December 31, 2007, and are recorded as discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3A. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer. The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods. See general discussion of guarantees at Note 22C.

On the date of the transaction, the carrying value of the disposed ownership interest totaled $37 million, which consisted primarily of the fair value of crude oil call options purchased in January 2007. Subsequent to the disposal, we remain the primary beneficiary of Ceredo and continue to consolidate Ceredo in accordance with FIN 46R, but record a 100 percent minority interest.

K. SYNTHETIC FUELS PARTNERSHIP INTERESTS

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

4. PROPERTY, PLANT AND EQUIPMENT

A. UTILITY PLANT

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

	Depreciable	Progress Energy		PEC		PEF	
(in millions)	Lives	**2008**	2007	**2008**	2007	**2008**	2007
Production plant	7-43	**$14,117**	$13,765	**$9,249**	$8,968	**$4,689**	$4,612
Transmission plant	17-75	**2,970**	2,684	**1,457**	1,361	**1,513**	1,323
Distribution plant	13-55	**8,028**	7,676	**4,330**	4,147	**3,698**	3,529
General plant and other	5-35	**1,211**	1,202	**662**	641	**549**	561
Utility plant in service		**$26,326**	$25,327	**$15,698**	$15,117	**$10,449**	$10,025

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

AFUDC represents the estimated costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant for certain projects in accordance with the regulatory provisions for each jurisdiction. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 9.2%, 8.8% and 8.7% in 2008, 2007 and 2006, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8% in 2008, 2007 and 2006.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.3%, 2.4% and 2.3% in 2008, 2007 and 2006, respectively. The depreciation provisions related to utility plant were $578 million, $560 million and $533 million in 2008, 2007 and 2006, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4D), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 7B).

PEC's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.1% for 2008, 2007 and 2006. The depreciation provisions related to utility plant were $310 million, $303 million and $294 million in 2008, 2007 and 2006, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4D), regulatory approved expenses (See Note 7B) and Clean Smokestacks Act amortization (See Note 7B).

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, was 2.7% in 2008, 2007 and 2006. The depreciation provisions related to utility plant were $268 million, $257 million and $239 million in 2008, 2007 and 2006, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4D) and regulatory approved expenses (See Note 7C).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, was $145 million, $139 million and $140 million for the years ended December 31, 2008, 2007 and 2006, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income. Amortization of nuclear fuel costs for the years ended December 31, 2008, 2007 and 2006 was $115 million, $110 million and $109 million, respectively, for PEC and $30 million, $29 million and $31 million, respectively, for PEF.

At December 31, 2008, PEF reflected $174 million of construction work in progress as recoverable regulatory assets pursuant to accelerated regulatory recovery of nuclear costs (See Note 7C).

B. DIVERSIFIED BUSINESS PROPERTY

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

PROGRESS ENERGY

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

(in millions)	**2008**	2007
Equipment (3-25 years)	**$5**	$6
Buildings (5-40 years)	**9**	9
Accumulated depreciation	**(8)**	(9)
Diversified business property, net	**$6**	$6

Diversified business depreciation expense was less than $1 million, $3 million and $2 million for the years ended December 31, 2008, 2007 and 2006, respectively.

PEC

Net diversified business property was $6 million at December 31, 2008, and $6 million at December 31, 2007. These amounts consist primarily of buildings and equipment that are being depreciated over periods ranging from 5 to 40 years. Accumulated depreciation was $3 million and $2 million at December 31, 2008 and 2007, respectively. Diversified business depreciation expense was less than $1 million each in 2008, 2007 and 2006.

C. JOINT OWNERSHIP OF GENERATING FACILITIES

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

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

2007 (in millions) Subsidiary	Facility	Company Ownership Interest	Plant	Accumulated	Construction Work in Progress
PEC	Mayo	83.83%	$519	$270	$156
PEC	Harris	83.83%	3,175	1,581	21
PEC	Brunswick	81.67%	1,647	959	16
PEC	Roxboro Unit 4	87.06%	637	422	39
PEF	Crystal River Unit 3	91.78%	817	450	177
PEF	Intercession City Unit P11	66.67%	23	9	–

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

D. ASSET RETIREMENT OBLIGATIONS

At December 31, 2008 and 2007, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant, net of accumulated depreciation for PEC, totaled $28 million and $29 million, respectively. At December 31, 2008, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant totaled $19 million at PEF. No costs related to nuclear decommissioning of irradiated plant were recorded at December 31, 2007, at PEF. At December 31, 2008 and 2007, additional PEF-related asset retirement costs, net of accumulated depreciation, of $116 million and $121 million, respectively, were recorded at Progress Energy as purchase accounting adjustments when we purchased Florida Progress Corporation (Florida Progress) in 2000. The fair value of funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $672 million and $804 million at December 31, 2008 and 2007, respectively, for PEC and $417 million and $580 million, respectively, for PEF. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 7A).

PEC's nuclear decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2008, 2007 and 2006. Management believes that nuclear decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 AROs, which are included in depreciation, amortization and accretion expense, were $100 million, $96 million and $96 million in 2008, 2007 and 2006, respectively, for PEC and $33 million, $30 million and $27 million in 2008, 2007 and 2006, 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. In 2009, PEF will be required to file an updated depreciation study.

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)	**2008**	2007	**2008**	2007	**2008**	2007
Removal costs	**$1,478**	$1,410	**$864**	$794	**$614**	$616
Nonirradiated decommissioning costs	**146**	141	**84**	80	**62**	61
Dismantlement costs	**124**	125	**–**	–	**124**	125
Non-ARO cost of removal	**$1,748**	$1,676	**$948**	$874	**$800**	$802

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC's most recent site-specific estimates of decommissioning costs were developed in 2004, using 2004 cost factors, and are based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2004 dollars, were $569 million for Unit No. 2 at Robinson Nuclear Plant (Robinson), $418 million for Brunswick Nuclear Plant (Brunswick) Unit No. 1, $444 million for Brunswick Unit No. 2 and $775 million for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. NRC operating licenses held by PEC currently expire in July 2030, December 2034, September 2036 and October 2046 for Robinson, Brunswick Units No. 2 and No. 1 and Harris, respectively. On December 17, 2008, Harris received a 20-year extension from the NRC on its operating license, which extends the operating license through 2046. 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. In 2009, PEC will be required to file an updated nuclear decommissioning study.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF received a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) in October 2008, which PEF will file with the FPSC in 2009 as part of PEF's planned base rate filing (See Note 7C). PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2008 dollars, is $751 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. PEF submitted an application requesting a 20-year extension of this license on December 18, 2008. PEF expects a decision from the NRC in 2011. As part of this new estimate and assumed license extension, PEF increased its asset retirement cost and its ARO liability by approximately $19 million. 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. PEF expects to continue this suspension based on its planned 2009 base rate filing. In addition, the wholesale accrual on PEF's reserves for nuclear decommissioning was suspended retroactive to January 2006, following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF received an updated fossil dismantlement study estimate in 2008, which PEF will file with the FPSC in 2009 as part of PEF's planned base rate filing. PEF's reserve for fossil plant dismantlement was approximately $145 million and $144 million at December 31, 2008 and 2007, 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.

PEC and PEF have recognized ARO liabilities related to asbestos abatement costs (See Note 1D). In 2008, PEC and PEF reduced the ARO liabilities related to asbestos abatement costs for the fossil plants by $4 million and $8 million, respectively, due to an updated study. An additional ARO liability was recognized in 2008 for landfill capping costs identified by both PEC and PEF of $1 million and $6 million, respectively.

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

The following table presents the changes to the AROs during the years ended December 31, 2008 and 2007. Revisions to prior estimates of the PEC and PEF regulated ARO are related to the updated cost estimates for nuclear decommissioning and asbestos described above.

	Progress Energy			
(in millions)	Regulated	Nonregulated	PEC	PEF
Asset retirement obligations at January 1, 2007	$1,303	$1	$1,004	$299
Accretion expense	75	–	59	16
Remediation	–	(1)	–	–
Asset retirement obligations at December 31, 2007	1,378	–	1,063	315
Additions	**7**	–	**1**	**6**
Accretion expense	**79**	–	**62**	**17**
Revisions to prior estimates	**7**	–	**(4)**	**11**
Asset retirement obligations at December 31, 2008	**$1,471**	**$–**	**$1,122**	**$349**

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 this program, following a 12-week deductible period, for 52 weeks in the amount of $3.5 million per week at Brunswick, Harris and Robinson, and $4.5 million per week at CR3. An additional 110 weeks of coverage is provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $37 million with respect to the primary coverage, $38 million with respect to the decontamination, decommissioning and excess property coverage, and $25 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate the plant, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $12.520 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from each insured nuclear incident exceed the primary level of coverage provided by American Nuclear Insurers, each company would be subject to pro rata assessments of up to $117.5 million for each reactor owned for each incident. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $17.5 million per reactor owned per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before August 29, 2013.

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

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

5. RECEIVABLES

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

	Progress Energy		PEC		PEF	
(in millions)	**2008**	2007	**2008**	2007	**2008**	2007
Trade accounts receivable	**$648**	$616	**$350**	$310	**$298**	$276
Unbilled accounts receivable	**182**	175	**120**	111	**62**	59
Notes receivable	**2**	67	–	–	–	–
Derivatives accounts receivable	–	247	–	–	–	13
Other receivables	**53**	46	**38**	31	**13**	13
Allowance for doubtful receivables	**(18)**	(29)	**(6)**	(6)	**(11)**	(10)
Total receivables, net	**$867**	$1,122	**$502**	$446	**$362**	$351

6. INVENTORY

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2008**	2007	**2008**	2007	**2008**	2007
Fuel for production	**$614**	$455	**$287**	$210	**$327**	$245
Materials and supplies	**588**	520	**338**	284	**250**	236
Emission allowances	**37**	19	**8**	16	**29**	3
Total inventory	**$1,239**	$994	**$633**	$510	**$606**	$484

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits on the Consolidated Balance Sheets for Progress Energy of $23 million and $65 million at December 31, 2008 and 2007, respectively, and PEC of $44 million at December 31, 2007.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits on the Consolidated Balance Sheets for Progress Energy, PEC and PEF of $61 million, $14 million and $47 million, respectively, at December 31, 2008. Long-term emission allowances for Progress Energy, PEC and PEF were $32 million, $3 million and $29 million, respectively, at December 31, 2007.

On November 12, 2008, the FPSC approved PEF's petition for recovery of its CAIR expenses, including nitrogen oxides (NOx) emission allowance inventory, through the environmental cost recovery clause (ECRC) (See Note 7C).

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.

Except for portions of deferred fuel costs and loss on reacquired debt, all regulatory assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. We anticipate recovering long-term deferred fuel costs beginning in 2010 and loss on reacquired debt over the applicable lives of the debt. We expect to fully recover our regulatory assets and refund our regulatory liabilities through customer rates under current regulatory practice.

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

Progress Energy

(in millions)	**2008**	2007
Deferred fuel cost – current (Notes 7B and 7C)	**$335**	$154
Nuclear deferral (Note 7C)	**190**	–
Environmental	**8**	–
Total current regulatory assets	**533**	154
Deferred fuel cost – long-term (Note 7B)	**130**	114
Deferred impact of ARO (Note 1D)	**348**	294
Income taxes recoverable through future rates (Note 14)	**193**	141
Loss on reacquired debt (Note 1D)	**37**	43
Storm deferral (Note 7C)	**16**	22
Postretirement benefits (Note 16)	**1,042**	212
Derivative mark-to-market adjustment (Note 17A)	**697**	18
Environmental (Notes 7C and 21A)	**31**	40
Investment in GridSouth (Note 7D)	**19**	22
Other	**54**	40
Total long-term regulatory assets	**2,567**	946
Deferred fuel cost – current (Note 7C)	**–**	(154)
Deferred energy conservation cost and other current regulatory liabilities	**(6)**	(19)
Total current regulatory liabilities	**(6)**	(173)
Non-ARO cost of removal (Note 4D)	**(1,748)**	(1,676)
Deferred impact of ARO (Note 1D)	**(198)**	(226)
Net nuclear decommissioning trust unrealized gains (Note 4D)	**(28)**	(351)
Derivative mark-to-market adjustment (Note 17A)	**(26)**	(200)
Storm reserve (Note 7C)	**(129)**	(63)
Other	**(52)**	(38)
Total long-term regulatory liabilities	**(2,181)**	(2,554)
Net regulatory assets (liabilities)	**$913**	$(1,627)

PEC

(in millions)	**2008**	2007
Deferred fuel cost – current (Note 7B)	**$207**	$148
Deferred fuel cost – long-term (Note 7B)	**130**	114
Deferred impact of ARO (Note 1D)	**343**	294
Income taxes recoverable through future rates (Note 14)	**62**	51
Loss on reacquired debt (Note 1D)	**16**	18
Postretirement benefits (Note 16)	**522**	126
Derivative mark-to-market adjustment (Note 17A)	**96**	4
Investment in GridSouth (Note 7D)	**19**	22
Other	**55**	51
Total long-term regulatory assets	**1,243**	680
Non-ARO cost of removal (Note 4D)	**(948)**	(874)
Net nuclear decommissioning trust unrealized gains (Note 4D)	**(21)**	(188)
Derivative mark-to-market adjustment (Note 17A)	**–**	(20)
Other	**(18)**	(16)
Total long-term regulatory liabilities	**(987)**	(1,098)
Net regulatory assets (liabilities)	**$463**	$(270)

PEF

(in millions)	**2008**	2007
Deferred fuel cost – current (Note 7C)	**$128**	$6
Nuclear deferral (Note 7C)	**190**	–
Environmental	**8**	–
Total current regulatory assets	**326**	6
Income taxes recoverable through future rates (Note 14)	**131**	90
Loss on reacquired debt (Note 1D)	**21**	25
Storm deferral (Note 7C)	**14**	16
Postretirement benefits (Note 16)	**520**	86
Derivative mark-to-market adjustment (Note 17A)	**601**	14
Environmental (Notes 7C and 21A)	**21**	30
Other	**16**	5
Total long-term regulatory assets	**1,324**	266
Deferred fuel cost – current (Note 7C)	**–**	(154)
Deferred energy conservation cost and other current regulatory liabilities	**(6)**	(19)
Total current regulatory liabilities	**(6)**	(173)
Non-ARO cost of removal (Note 4D)	**(800)**	(802)
Deferred impact of ARO (Note 1D)	**(76)**	(96)
Net nuclear decommissioning trust unrealized gains (Note 4D)	**(7)**	(163)
Derivative mark-to-market adjustment (Note 17A)	**(26)**	(180)
Storm reserve (Note 7C)	**(129)**	(63)
Other	**(38)**	(26)
Total long-term regulatory liabilities	**(1,076)**	(1,330)
Net regulatory assets (liabilities)	**$568**	$(1,231)

B. PEC RETAIL RATE MATTERS

BASE RATES

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

On March 23, 2007, PEC filed a petition with the NCUC requesting that it be allowed to amortize the remaining 30 percent (or $244 million) of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, with discretion to amortize up to $174 million in either year. Additionally, among other things, PEC requested in its March 23, 2007 petition that the NCUC allow PEC to include in its rate base those eligible compliance costs exceeding the original estimated compliance costs and that PEC be allowed to accrue AFUDC on all eligible compliance costs in excess of the original estimated compliance costs. PEC also requested that any prudency review of PEC's environmental compliance costs be deferred until PEC's next ratemaking proceeding in which PEC seeks to adjust its base rates. On October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, the Carolina Utility Customers Association (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis, with the NCUC indicating that it intended to initiate a review in 2009 to consider all reasonable alternatives and proposals related to PEC's recovery of its Clean Smokestacks Act compliance costs in excess of the original estimated compliance costs of $813 million.

On July 10, 2008, PEC filed a petition with the NCUC requesting that the NCUC reconsider its order issued December 20, 2007, and terminate the requirement that PEC amortize any Clean Smokestacks Act compliance costs in excess of $569 million, and instead allow PEC to place into rate base all capital costs associated with its compliance with the Clean Smokestacks Act in excess of $569 million.

On September 5, 2008, the NCUC approved PEC's request to terminate any further accelerated amortization of its Clean Smokestacks Act compliance costs. The NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million as the projects are closed to plant in service. As a result of this order, PEC will not amortize $229 million of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, but will record depreciation over the useful life of the assets.

For the years ended December 31, 2008, 2007 and 2006, PEC recognized amortization of $15 million, $34 million and $140 million, respectively, and recognized $584 million in cumulative amortization through December 31, 2008.

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

FUEL COST RECOVERY

On April 30, 2008, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers. PEC asked the SCPSC to approve a $39 million increase in fuel rates for under-recovered fuel costs associated with prior year settlements and to meet future expected fuel costs. On June 26, 2008, the SCPSC approved PEC's request. Effective July 1, 2008, residential electric bills increased by $5.86 per 1,000 kilowatt-hours (kWh), or 6.1 percent, for fuel cost recovery. At December 31, 2008, PEC's South

Carolina under-recovered deferred fuel balance was $15 million.

On June 6, 2008, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. Subsequently, PEC jointly filed a settlement agreement with CIGFUR, CUCA and the NCUC Public Staff. Under the terms of the settlement agreement, PEC will collect $203 million of deferred fuel costs ratably over a three-year period beginning December 1, 2008, compared with a one-year recovery period proposed in PEC's original request. Amounts to be collected in years beginning December 1, 2009 and 2010, will accrue interest. On November 14, 2008, the NCUC approved the settlement agreement. Effective December 1, 2008, residential electric bills increased by $8.79 per 1,000 kWh, or 9.1 percent. At December 31, 2008, PEC's North Carolina deferred fuel balance was $321 million, of which $130 million is expected to be collected after 2009 and has been classified as a long-term regulatory asset.

DEMAND-SIDE MANAGEMENT AND ENERGY-EFFICIENCY COST RECOVERY

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. Among other provisions, the law allows the utility to recover the costs of demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs intended to produce future benefits and authorizes the NCUC to approve other forms of financial incentives to the utility for DSM and energy-efficiency programs. DSM programs include, but are not limited to, any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control, interruptible load and electric system equipment and operating controls. PEC has begun implementing a series of DSM and energy-efficiency programs and, as of December 31, 2008, has deferred $8 million of implementation and program costs for future recovery. In 2008, PEC filed for NCUC approval of multiple DSM and energy-efficiency programs. The majority of the programs has been approved by the NCUC or is pending further review. We cannot predict the outcome of the DSM and energy-efficiency filings pending further approval by the NCUC or whether the programs will produce the expected operational and economic results.

On June 6, 2008, and as subsequently amended, PEC filed an application with the NCUC for approval of a DSM and energy-efficiency clause to recover the costs of these programs and a return on the costs. Although the NCUC is not expected to make a decision on this filing until first quarter 2009, on November 14, 2008, the NCUC approved PEC collecting the DSM and energy-efficiency related costs beginning December 1, 2008. On December 9, 2008, the North Carolina Public Staff filed an Agreement and Stipulation of Partial Settlement with PEC and some of the other parties to the proceedings. The NCUC held a hearing on the matter on January 7, 2009. If the rates being collected as of December 1, 2008, are approved, residential electric bills would increase by $0.74 per 1,000 kWh, or 0.8 percent. The increase in rates is subject to true-up in future proceedings. We cannot predict the outcome of this matter.

PEC filed a petition on November 30, 2007, with the SCPSC seeking authorization to create a deferred account for DSM and energy-efficiency expenses. On December 21, 2007, the SCPSC issued an order granting PEC's petition. As a result, PEC has deferred $1 million of implementation and program costs for future recovery in the South Carolina jurisdiction. On June 27, 2008, PEC filed an application with the SCPSC to establish procedures that encourage investment in cost-effective energy-efficient technologies and energy conservation programs and approve the establishment of an annual rider to allow recovery for all costs associated with such programs, as well as the recovery of appropriate incentives for investing in such programs. On January 23, 2009, PEC filed a Stipulation Agreement between PEC and some of the other parties to the proceeding. A hearing on this matter was held on February 12, 2009. We cannot predict the outcome of this matter.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD COST RECOVERY

On February 29, 2008, the NCUC issued an order adopting final rules for implementing North Carolina's comprehensive energy legislation. These rules provide filing requirements associated with the legislation. The order required PEC to submit its first annual Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) compliance plan as part of its integrated resource plan, which was filed on September 2, 2008. Under the new rules, beginning in 2009, PEC will also be required to file an annual NC REPS compliance report demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC REPS requirement via renewable energy certificates (REC) earned after January 1, 2008. The NCUC will pursue a third-party REC tracking system, but will not develop or require participation in a REC trading platform at this time. Rates for the NC REPS clause will be set based on projected costs with true-up provisions. On June 6, 2008, and as amended on August 22, 2008, PEC filed an application with the NCUC for approval of a NC REPS clause to recover the costs of this program. On November 14, 2008, the NCUC approved a monthly charge per customer rather than a usage-based rate. Effective December 1, 2008, residential electric bills increased $0.36 per month.

OTHER MATTERS

The NCUC and the SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The North Carolina aggregate minimum and maximum amounts of cost recovery are $415 million and $585 million, respectively, with flexibility in the amount of annual depreciation recorded, from none to $150 million per year. Accelerated cost recovery of these assets resulted in additional depreciation expense of $52 million and $37 million for the years ended December 31, 2008 and 2007, respectively. No additional depreciation expense from accelerated cost recovery was recorded in 2006. Through December 31, 2008, PEC recorded cumulative accelerated depreciation of $415 million for the North Carolina jurisdiction. The South Carolina aggregate minimum and maximum amounts of cost recovery are $115 million and $165 million, respectively. No additional depreciation expense from accelerated cost recovery was recorded in 2008, 2007 or 2006. Through December 31, 2008, PEC recorded cumulative accelerated depreciation of $77 million for the South Carolina jurisdiction.

In October 2008, PEC filed, and the SCPSC approved, a petition to terminate PEC's remaining obligation to accelerate the cost recovery of PEC's nuclear generating assets. As a result of the approval of this petition, PEC will not be required to recognize the remaining $38 million of accelerated depreciation required to reach the minimum amount of cost recovery for the South Carolina jurisdiction, but will record depreciation over the useful life of the assets.

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

On April 30, 2008, PEC submitted a revised Open Access Transmission Tariff (OATT) filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula rates for the PEC OATT in order to more accurately reflect the costs that PEC incurs in providing transmission service. In the filing, PEC proposed to move from a fixed revenue requirement to a formula rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. Settlement discussions were held with major customers prior to the filing and a settlement agreement was reached on all issues. The settlement proposed a formula rate with a rate of return on equity of 10.8 percent as well as recovery of the wholesale portion of the terminated GridSouth Transco, LLC (GridSouth) project startup costs over five years. On June 27, 2008, the FERC approved the settlement. The new rates were effective July 1, 2008, and increased 2008 revenues by $7 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 pursuant to the agreement. In accordance with the base rate agreement and as modified by a stipulation and settlement agreement approved by the FPSC on October 23, 2007, base rates were adjusted in January 2008 due to specified generation facilities placed in service in 2007. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006, whereby PEF will refund two-thirds of retail base revenues between the specified threshold and specified cap and 100 percent of revenues above the specified cap. However, PEF's retail base revenues did not exceed the specified thresholds in 2008, 2007 or 2006 and thus no revenues were subject to revenue sharing. Both the base threshold and the cap will be adjusted annually for rolling average 10-year retail kWh sales growth and were $1.664 billion and $1.716 billion, respectively, for 2008. 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 cost-recovery clause return calculations. PEF will use an authorized 11.75 percent return on equity 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 return on equity falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

On February 12, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2010. In its notice, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and that it intends to seek annual rate relief between $475 million to $550 million. PEF intends to file its case-in-chief on March 20, 2009. The request for increased base rates is based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems. If approved by the FPSC, the new base rates would increase residential bills by approximately $15.00 per 1,000 kWh, or 11 percent, effective January 1, 2010. We cannot predict the outcome of this matter.

As part of its February 12, 2009 notification, PEF also informed the FPSC that it may seek additional rate relief in 2009, primarily driven by the addition of its repowered Bartow power plant, which is expected to begin commercial operation in June 2009, and decreased sales and higher pension costs impacted by the current financial and credit crises. We cannot predict the outcome of this matter.

FUEL COST RECOVERY

On September 4, 2007, PEF filed a request with the FPSC seeking approval of a cost adjustment to reflect a projected over-collection of fuel costs in 2007, declining projected fuel costs for 2008 and other recovery clause factors. On January 8, 2008, the FPSC issued an order approving PEF's request for a $163 million, or 4.53 percent, decrease in rates effective January 1, 2008.

On May 30, 2008, PEF filed a petition with the FPSC requesting a mid-course correction to its fuel cost-recovery factors to recover an additional $213 million in 2008, primarily due to rising fuel costs. In accordance with a FPSC order, investor-owned utilities must file a notice with the FPSC if the year-end projected over- or under-recovery of fuel costs is expected to be greater than 10 percent of projected fuel revenues. The requested mid-course correction would have resulted in a residential fuel rate increase of $12.07 per 1,000 kWh for the period August through December 2008. On July 1, 2008, the FPSC approved recovery of the $213 million projected year-end under-recovery, but allowed PEF to recover 50 percent in 2008 and 50 percent in 2009. Therefore, the increase in the fuel rate for the period August through December 2008 was $6.03 per 1,000 kWh. This increase was partially offset by the expiration of PEF's storm cost-recovery surcharge of $3.61 per 1,000 kWh effective August 2008. Consequently, beginning with the first billing cycle in August and including gross receipts tax, residential electric bills increased by $2.48 per 1,000 kWh, or 2.29 percent. As discussed in "Base Rate Agreement," residential base rates increased effective January 1, 2008, due to specified generation facilities placed in service in 2007. The costs of certain of these facilities had previously been recovered through the fuel clause.

On October 15, 2008, PEF filed a request with the FPSC to seek approval of a cost adjustment for the under-recovery of fuel costs in 2008 and other recovery-clause factors. PEF asked the FPSC to approve an increase in residential electric bills by $27.28 per 1,000 kWh, or 24.7 percent, effective January 1, 2009. The increase in residential bills is primarily due to increases of $14.09 per 1,000 kWh for the projected recovery of fuel costs, $9.74 per 1,000 kWh for the projected recovery through the capacity cost-recovery clause and $2.50 per 1,000 kWh for the projected recovery through the ECRC. The increase in the capacity cost-recovery clause is primarily the result of projected costs to be incurred in 2009 under the nuclear cost-recovery rule discussed below for the proposed Levy Units 1 and 2 and the CR3 uprate less the projected reduction in capacity costs. The increase in the ECRC is primarily due to the recovery of emission allowance costs (See Note 21B) and the return on assets expected to be placed in service in 2009. The FPSC issued orders in November and December 2008 to approve the cost adjustment. At December 31, 2008, PEF's under-recovered deferred fuel balance was $128 million.

On February 18, 2009, PEF filed a request with the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $207 million reduction in fuel charges to retail customers as a result of effective fuel purchasing strategies and lower fuel prices, and to defer until 2010 the recovery of $200 million of Levy nuclear preconstruction costs, which the FPSC had authorized to be collected in 2009. If approved, the request would reduce residential customers' fuel charges by $6.90 per 1,000 kWh, and would reduce the nuclear cost-recovery charge by $7.80 per 1,000 kWh, starting with the first April billing cycle. Commercial and industrial customers would see similar reductions. We cannot predict the outcome of this matter.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and SO_2 allowance costs during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. The OPC claimed that although Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) were designed to burn a blend of coals, PEF failed to act to lower ratepayers' costs by purchasing the most economical blends of coal. During the period specified in the petition, PEF's costs recovered through fuel recovery clauses were annually reviewed for prudence and approval by the FPSC. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the FPSC found that PEF had not been prudent in purchasing a portion of its coal requirements during the period from 2003 to 2005. Accordingly, the FPSC ordered PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. For the year ended December 31, 2007, PEF recorded a pre-tax other operating expense of $12 million, interest expense of $2 million and an associated $14 million regulatory liability included within PEF's deferred fuel cost at December 31, 2007. The refund was returned to ratepayers through a reduction of prior year under-recovered fuel costs. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. On October 4, 2007, PEF filed a motion to establish a separate docket on the prudence of its coal purchases for CR4 and CR5 for the years 2006 and 2007. On October 17, 2007, the FPSC granted that motion. PEF believes its coal procurement practices have been prudent. A hearing on PEF's 2006 and 2007 coal purchases has been scheduled for April 13-15, 2009. On February 2, 2009, the OPC filed direct testimony in this hearing alleging that during 2006 and 2007, PEF collected excessive fuel costs and SO_2 allowance costs of $61 million before interest. The OPC claimed that these excessive costs were attributed to PEF's ongoing practice of not blending the most economical sources of coal at its CR4 and CR5 plants. We cannot predict the outcome of this matter.

NUCLEAR COST RECOVERY

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

CR3 Uprate

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate CR3 and bid rule exemption, and for recovery of the revenue requirements of the uprate through PEF's fuel recovery clause. To the extent the expenditures are prudently incurred, PEF's investment in the CR3 uprate is eligible for recovery through base rates. PEF's petition would allow for more prompt recovery. The petition filed with the FPSC included a preliminary project estimate of approximately $382 million. The multi-stage uprate will increase CR3's gross output by approximately 180 MW by 2012. On February 8, 2007, the FPSC issued an order approving the need certification petition and bid rule exemption. PEF received NRC approval for a license amendment and implemented the first stage's design modification on January 31, 2008, at a cost of $9 million. PEF will apply for the required license amendment for the third stage's design modification. After PEF's completion of a transmission study and additional engineering studies, the current project estimate of fully loaded costs is $364 million.

On February 29, 2008, PEF filed a petition amending its recovery request and asked for recovery of costs incurred in 2007 and 2006 through the capacity cost-recovery clause under Florida's comprehensive energy legislation and the FPSC's nuclear cost-recovery rule. On August 19, 2008, the FPSC granted PEF's petition to amend its request to recover costs for the nuclear uprate project under the nuclear cost-recovery rule. On May 1, 2008, PEF filed with the FPSC for an increase in the capacity cost-recovery clause for estimated costs incurred in 2008 and projected costs to be incurred in 2009 under the FPSC nuclear cost-recovery rule. PEF petitioned the FPSC to approve a $25 million increase in the capacity cost-recovery revenue requirement for costs associated with subsequent stages of the CR3 uprate.

On September 19, 2008, PEF filed a petition with the FPSC to approve a base rate increase for the remaining revenue requirements for the first-stage costs. PEF's 2008 revenue requirements for recovery of the first stage's costs were included in the capacity cost-recovery clause. On October 28, 2008, the FPSC approved a $1 million base rate increase for costs associated with the first stage of the CR3 uprate. Base rates increased for residential customers by $0.04 per 1,000 kWh, or 0.1 percent, beginning in January 2009. On November 12, 2008, the FPSC issued an order to approve $24 million for costs associated with the CR3 uprate in establishing PEF's 2009 capacity cost-recovery clause factor.

Levy Nuclear

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

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

As discussed above in "Fuel Cost Recovery," on February 18, 2009, PEF filed a request with the FPSC to defer the recovery of $200 million of Levy nuclear preconstruction costs.

STORM COST RECOVERY

In 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power associated with four hurricanes in 2004. The net impact was included in customer bills beginning January 1, 2006. In 2007 and 2006, PEF recorded amortization of $75 million and $122 million, respectively, associated with the recovery of these storm costs. The retail portion of storm restoration costs were fully recovered at December 31, 2007.

On April 25, 2006, PEF entered into a settlement agreement with certain intervenors in its storm cost-recovery docket that would allow PEF to extend its then-current two-year storm surcharge, which equals approximately $3.61 on the average residential monthly customer bill of 1,000 kWh, for an additional 12-month period to replenish its storm reserve. The requested extension, which began August 2007, was expected to replenish the existing storm reserve by an estimated $126 million. During the third quarter of 2006, PEF and the intervenors modified the settlement agreement such that in the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence. On August 29, 2006, the FPSC approved the settlement agreement as modified. In 2008, PEF recorded net additional storm reserve of $66 million from the extension of the storm surcharge. At December 31, 2008, PEF's storm reserve totaled $129 million.

OTHER MATTERS

On October 29, 2007, PEF submitted a revised OATT filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula rates for the PEF OATT in order to more accurately reflect the costs that PEF incurs in providing transmission service. In the filing, PEF proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. Settlement discussions were held with major customers prior to the filing and a settlement agreement was reached on all issues. The settlement proposed a formula rate with a rate of return on equity of 10.8 percent. PEF received FERC approval of the settlement agreement on December 17, 2007. The new rates were effective January 1, 2008, and increased 2008 revenues by $2 million.

D. REGIONAL TRANSMISSION ORGANIZATIONS

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

On November 16, 2007, PEC petitioned the NCUC to allow it to establish a regulatory asset for PEC's development costs of GridSouth pending disposition in a general rate proceeding. On January 14, 2008, the NCUC issued an order requesting interested parties to file comments regarding PEC's petition on or before January 28, 2008. On February 11, 2008, PEC filed response comments. On December 20, 2007, the NCUC issued an order for one of the other GridSouth partners. As part of that order, the NCUC ruled that the utility's GridSouth development costs should be amortized and recovered over a 10-year period beginning June 2002. Consequently, in 2007, PEC recorded an $11 million charge to amortization expense. On June 4, 2008, the NCUC issued an order granting PEC the same accounting treatment to its GridSouth development costs. In accordance with the OATT settlement discussed above, in July 2008, PEC began amortization and recovery of the wholesale portion of PEC's GridSouth development costs over a five-year period. The impact of this wholesale amortization was $1 million in 2008 and is estimated to be $2 million annually during the remaining amortization period. PEC's recorded investment in GridSouth totaled $19 million and $22 million at December 31, 2008 and 2007, respectively.

E. NUCLEAR LICENSE RENEWALS

The NRC operating license for Robinson expires in 2030 and the licenses for Brunswick expire in 2036 for Unit No. 1 and 2034 for Unit No. 2. On December 17, 2008, the NRC issued a 20-year extension on the operating license for Harris, which extends the operating license through 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On December 18, 2008, PEF filed an application for a 20-year extension from the NRC on the operating license for CR3, which would extend the operating license through 2036, if approved. PEF anticipates a decision from the NRC in 2011.

8. GOODWILL AND INTANGIBLE ASSETS

We perform annual goodwill impairment tests in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Goodwill was tested for impairment for both the PEC and PEF segments in the second quarters of 2008 and 2007; 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, 2008 and 2007, 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 2008 or 2007.

Goodwill was previously allocated to our former CCO-Georgia Operations reporting unit, which was comprised of four nonregulated generating plants. As a result of our evaluation of certain business opportunities that impacted the future cash flows of our Georgia 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 has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income (See Note 3C).

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 3A). The impairment test considered numerous factors including, among other things, continued high oil prices and the then-current idled state of our synthetic fuels facilities. We estimated the fair value using the expected present value of future cash flows. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $27 million ($17 million after-tax) during the quarter ended June 30, 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income.

9. EQUITY

A. COMMON STOCK

PROGRESS ENERGY

At December 31, 2008 and 2007, we had 500 million shares of common stock authorized under our charter, of which 264 million shares and 260 million shares, respectively, were outstanding. During 2008, 2007 and 2006, respectively, we issued approximately 3.7 million, 3.7 million and 4.2 million shares of common stock, resulting in approximately $132 million, $151 million and $185 million in proceeds. Included in these amounts for 2008, 2007 and 2006, respectively, were approximately 3.1 million, 1.0 million and 1.6 million shares for proceeds of approximately $131 million, $46 million and $70 million, issued for the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan.

On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were approximately $523 million.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2008, there were no significant restrictions on the use of retained earnings (See Note 11B).

PEC

At December 31, 2008 and 2007, 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, 2008, there were no significant restrictions on the use of retained earnings. See Note 11B for additional dividend restrictions related to PEC.

PEF

At December 31, 2008 and 2007, 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, 2008, there were no significant restrictions on the use of retained earnings. See Note 11B for additional dividend restrictions related to PEF.

B. STOCK-BASED COMPENSATION

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. At December 31, 2008 and 2007, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes.

There were 1.1 million and 1.7 million ESOP suspense shares at December 31, 2008 and 2007, respectively, with a fair value of $45 million and $82 million, respectively. ESOP shares allocated to plan participants totaled 12.6 million and 10.6 million at December 31, 2008 and 2007, 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 $8 million, $23 million and $14 million for the years ended December 31, 2008, 2007 and 2006, respectively. Total matching and incentive costs were approximately $34 million, $30 million and $23 million for the years ended December 31, 2008, 2007 and 2006, respectively. We have a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

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

PEC

PEC's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $5 million, $14 million and $8 million for the years ended December 31, 2008, 2007 and 2006, respectively. Total matching and incentive costs were approximately $21 million, $18 million and $13 million for the years ended December 31, 2008, 2007 and 2006, respectively.

PEF

PEF's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $1 million, $4 million and $2 million for the years ended December 31, 2008, 2007 and 2006, respectively. Total matching and incentive costs were approximately $7 million, $6 million and $4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

STOCK OPTIONS

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

PROGRESS ENERGY

A summary of the status of our stock options at December 31, 2008, and changes during the year then ended, is presented below:

(option quantities in millions)	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	1.7	$43.99
Canceled	–	44.38
Exercised	(0.1)	43.83
Options outstanding, December 31	1.6	43.99
Options exercisable, December 31	1.6	43.99

The options outstanding and exercisable at December 31, 2008, had a weighted-average remaining contractual life of 4.0 years. Aggregate intrinsic value as of December 31, 2008, was not significant. Total intrinsic value of options exercised during the years ended December 31, 2007 and 2006, respectively, was $17 million and $10 million. The total intrinsic value of options exercised during the year ended December 31, 2008, was not significant.

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

At December 31, 2006, all options were fully vested; therefore, no compensation expense was recognized in 2008 or 2007. Stock option expense totaling $2 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year.

Cash received from the exercise of stock options totaled $1 million, $105 million and $115 million, respectively, during the years ended December 31, 2008, 2007 and 2006. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2007 and 2006, was $6 million and $4 million, respectively. The actual tax benefit deduction for stock option exercises for the year ended December 31, 2008, was not significant.

PEC

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. As of December 31, 2006, all options were fully vested; therefore, no compensation expense was recognized in 2008 or 2007.

PEF

Stock option expense totaling less than $1 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. As of December 31, 2006, all options were fully vested; therefore, no compensation expense was recognized in 2008 or 2007.

OTHER STOCK-BASED COMPENSATION PLANS

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

We granted cash-settled PSSP awards prior to 2005. Since 2005, we have been granting stock-settled PSSP awards. Under the terms of the PSSP, our officers and key employees are granted a target number of performance shares on an annual basis that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of Progress Energy common stock, and dividend equivalents are accrued on, and reinvested in, additional performance shares. Prior to 2007, shares issued under the PSSP (both cash-settled and stock-settled) had two equally weighted performance measures, both based on our results as compared to a peer group of utilities. In 2007, the PSSP was redesigned, and shares issued under the revised plan use one performance measure. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. For cash-settled awards, compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated to reflect factors such as changes in stock price and the status of performance measures. The stock-settled PSSP is similar to the cash-settled PSSP, except that we distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. We issue new shares of common stock to satisfy the requirements of the PSSP program. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with subsequent adjustments made to reflect the status of the performance measure. Compensation expense for all awards is reduced by estimated forfeitures. PSSP cash-settled liabilities totaling $2 million, $3 million and $4 million were paid in the years ended December 31, 2008, 2007 and 2006, respectively. A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2008, and changes during the year then ended is presented below:

	Number of Stock-Settled Performance Shares (a)	Weighted-Average Grant Date Fair Value
Beginning balance	1,629,995	$44.97
Granted	271,964	42.41
Vested	(441,435)	44.23
Paid(b)	(228,793)	50.70
Forfeited	(113,127)	44.76
Ending balance	1,118,604	46.46

(a) Amounts reflect target shares to be issued. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.
(b) Shares paid include only target shares as originally granted. Additional shares of 131,881 were issued and paid due to exceeding established performance thresholds and due to dividends earned.

For the years ended December 31, 2007 and 2006, the weighted-average grant date fair value of stock-settled performance shares granted was $50.70 and $44.27, respectively.

The Restricted Stock Award program allows us to grant shares of restricted common stock to our officers and key employees. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. Restricted shares are 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, 2008, and changes during the year then ended, is presented below:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	268,635	$43.77
Granted	—	—
Vested	(71,134)	43.29
Forfeited	(5,400)	44.63
Ending balance	192,101	43.93

For the years ended December 31, 2007 and 2006, the weighted-average grant date fair value of restricted stock granted was $49.54 and $44.51, respectively.

The total fair value of restricted stock awards vested during the years ended December 31, 2008, 2007 and 2006 was $3 million, $13 million and $4 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million during the year ended December 31, 2006. Cash expended to purchase shares for 2008 and 2007 was not significant due to the curtailment of the Restricted Stock Award program and the rollout of the new restricted stock unit (RSU) program.

Beginning in 2007, we began issuing RSUs rather than restricted stock awards for our officers, vice presidents, managers and key employees. RSUs awarded to eligible employees are generally subject to either three- or five-year cliff vesting or five-year graded vesting. We issue new shares of common stock to satisfy the requirements of the RSU program. Compensation expense, based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. RSUs are not included as shares outstanding in the basic earnings per share calculation until shares are no longer forfeitable. Units are converted to shares upon vesting. A summary of the status of nonvested RSUs at December 31, 2008, and changes during the year then ended, is presented below:

	Number of Restricted Units	Weighted-Average Grant Date Fair Value
Beginning balance	824,458	$50.29
Granted	489,603	42.48
Vested	(187,318)	46.67
Forfeited	(50,207)	50.55
Ending balance	1,076,536	46.86

The total fair value of RSUs vested during the year ended December 31, 2008, was $9 million. There were no expenditures to purchase stock to satisfy RSU plan obligations in 2008.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $31 million for the year ended December 31, 2008, with a recognized tax benefit of $12 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $64 million with a recognized tax benefit of $24 million and $25 million, with a recognized tax benefit of $10 million, for the years ended December 31, 2007 and 2006, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2008, there was $34 million of total unrecognized compensation cost related to nonvested other stock-based compensation plan awards, which is expected to be recognized over a weighted-average period of 1.57 years.

PEC

PEC's Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $18 million for the year ended December 31, 2008, with a recognized tax benefit of $7 million. The total expense recognized on PEC's Consolidated Statements of Income for other stock-based compensation plans was $38 million with a recognized tax benefit of $15 million and $14 million, with a recognized tax benefit of $6 million, for the years ended December 31, 2007 and 2006, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

PEF

PEF's Statements of Income included total recognized expense for other stock-based compensation plans of $13 million for the year ended December 31, 2008, with a recognized tax benefit of $5 million. The total expense recognized on PEF's Statements of Income for other stock-based compensation plans was $21 million with a recognized tax benefit of $8 million and $7 million, with a recognized tax benefit of $3 million, for the years ended December 31, 2007 and 2006, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

C. EARNINGS PER COMMON SHARE

Basic earnings per common share are based on the weighted-average number of common shares outstanding. Diluted earnings per share include the effects of the nonvested portion of restricted stock, restricted stock unit awards and performance share awards and the effect of stock options outstanding.

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

(in millions)	**2008**	2007	2006
Weighted-average common shares – basic	**260.3**	256.1	250.4
Net effect of dilutive stock-based compensation plans	**0.5**	0.6	0.4
Weighted-average shares – fully diluted	**260.8**	256.7	250.8

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 ESOP shares totaled 1.2 million, 1.8 million and 2.4 million for the years ended December 31, 2008, 2007 and 2006, respectively. There were 1.6 million, 0.1 million and 1.8 million stock options outstanding at December 31, 2008, 2007 and 2006, 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)	**2008**	2007	**2008**	2007	**2008**	2007
Loss on cash flow hedges	**$(57)**	$(23)	**$(35)**	$(10)	**$(1)**	$(8)
Pension and other postretirement benefits	**(58)**	(13)	–	–	–	–
Other	**(1)**	2	–	–	–	–
Total accumulated other comprehensive loss	**$(116)**	$(34)	**$(35)**	$(10)	**$(1)**	$(8)

10. 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, 2008 and 2007, preferred stock outstanding consisted of the following:

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

11. DEBT AND CREDIT FACILITIES

A. DEBT AND CREDIT FACILITIES

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2008):

(in millions)		**2008**	2007
Parent			
Senior unsecured notes, maturing 2010-2031	6.96%	**$2,600**	$2,600
Draws on revolving credit agreement, expiring 2012	2.52%	**100**	–
Unamortized premium and discount, net		**(4)**	(3)
Long-term debt, net		**2,696**	2,597
PEC			
First mortgage bonds, maturing 2009-2038	5.74%	**2,325**	2,000
Pollution control obligations, maturing 2017-2024	2.25%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Medium-term notes		**-**	300
Miscellaneous notes	6.01%	**22**	22
Unamortized premium and discount, net		**(7)**	(8)
Current portion of long-term debt		**-**	(300)
Long-term debt, net		**3,509**	3,183
PEF			
First mortgage bonds, maturing 2010-2038	5.81%	**3,800**	2,380
Pollution control obligations, maturing 2018-2027	1.63%	**241**	241
Senior unsecured notes		**-**	450
Medium-term notes, maturing 2028	6.75%	**150**	152
Unamortized premium and discount, net		**(9)**	(5)
Current portion of long-term debt		**-**	(532)
Long-term debt, net		**4,182**	2,686
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(37)**	(38)
Long-term debt, net		**272**	271
Progress Capital Holdings, Inc.			
Medium-term notes		**-**	45
Current portion of long-term debt		**-**	(45)
Long-term debt, net		**-**	–
Progress Energy consolidated long-term debt, net		**$10,659**	$8,737

At December 31, 2008, the Parent had a revolving credit agreement (RCA) used to support its commercial paper borrowings. We classified $100 million of the $600 million outstanding under the Parent's RCA as long-term debt. Settlement of a portion of this obligation did not require the use of working capital in 2009 as $100 million of the proceeds from the January 12, 2009 equity issuance was used to reduce RCA borrowings. No amount was outstanding under the Parent's RCA at December 31, 2007. Additionally, we classified PEC's $400 million 5.95% Senior Notes, due March 1, 2009, as long-term debt, as the maturity will be paid with the proceeds of PEC's $600 million January 15, 2009 debt issuance discussed below.

On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038. The proceeds were used to repay the maturity of PEC's $300 million 6.65% Medium-Term Notes, Series D, due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.

On February 1, 2008, PEF paid at maturity $80 million of its 6.875% First Mortgage Bonds with available cash on hand and commercial paper borrowings. On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.

On May 27, 2008, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity its remaining outstanding debt of $45 million of 6.46% Medium-Term Notes with available cash on hand.

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

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

At December 31, 2008 and 2007, we had committed lines of credit used to support our commercial paper borrowings. As a result of financial and economic conditions in 2008, the short-term credit markets tightened, resulting in volatility in commercial paper durations and interest rates. On November 3, 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets, which is reflected in the outstanding borrowings under our credit facilities as shown in the table below. As discussed above, of the $600 million outstanding, $100 million was classified as long-term debt at December 31, 2008. We will continue to monitor the commercial paper and short-term credit markets to determine when to repay the outstanding balance of the RCA loan, while maintaining an appropriate level of liquidity. At December 31, 2007, 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 RCAs and available capacity at December 31, 2008:

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

(a) In February 2009, the Parent repaid $100 million of its outstanding RCA borrowings.

(b) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2008, the Parent had $30 million of letters of credit issued, which were supported by the RCA.

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

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

(in millions)	**2008**		2007	
Parent	**2.81%**	**$569**	5.48%	$201
PEC	**4.36%**	**110**		–
PEF	**4.41%**	**371**		–
Total	**3.54%**	**$1,050**		$201

The following table presents the aggregate maturities of long-term debt at December 31, 2008:

(in millions)	Progress Energy Consolidated	PEC	PEF
2009	$–	$–	$–
2010	406	6	300
2011	1,000	–	300
2012	1,050	500	–
2013	825	400	425
Thereafter	7,435	2,610	3,166
Total	$10,716	$3,516	$4,191

B. COVENANTS AND DEFAULT PROVISIONS

FINANCIAL COVENANTS

The Parent's, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2008, the maximum and calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio [a]
Parent	68%	57.8%
PEC	65%	45.5%
PEF	65%	58.6%

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

CROSS-DEFAULT PROVISIONS

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

Additionally, certain of the Parent's long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of the Parent, primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $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 the Parent's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. At December 31, 2008, the Parent had no shares of preferred stock outstanding.

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

PEC

PEC's mortgage indenture provides that, as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million, less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2008, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2008, PEC's common stock equity was approximately 54.7 percent of total capitalization. At December 31, 2008, 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, 2008, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2008, PEF's common stock equity was approximately 44.6 percent of total capitalization. At December 31, 2008, 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, 2008, PEC and PEF had a total of $2.994 billion and $4.041 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. GUARANTEES OF SUBSIDIARY DEBT

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

E. HEDGING ACTIVITIES

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

12. INVESTMENTS

A. INVESTMENTS

At December 31, 2008 and 2007, 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)	**2008**	2007	**2008**	2007	**2008**	2007
Nuclear decommissioning trust (See Note 4D)	**$1,089**	$1,384	**$672**	$804	**$417**	$580
Equity method investments [(a)]	**22**	23	**9**	11	**2**	2
Cost investments [(b)]	**7**	8	**3**	3	**–**	–
Company-owned life insurance [(c)]	**49**	51	**34**	34	**–**	–
Benefit investment trusts [(d)]	**184**	199	**85**	80	**30**	39
Marketable debt securities	**1**	1	**1**	1	**–**	–
Total	**$1,352**	$1,666	**$804**	$933	**$449**	$621

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

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

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

(d) Benefit investment trusts are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 2008 and 2007, $142 million and $155 million, respectively, of investments in company-owned life insurance were held in Progress Energy's trusts. Substantially all of PEC's and PEF's benefit investment trusts are invested in company-owned life insurance.

B. IMPAIRMENT OF INVESTMENTS

We evaluate declines in value of investments under the criteria of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), and FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairments and Its Application to Certain Investments" (See Note 1D). Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in long-term regulatory liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the Consolidated Statements of Income for securities in our benefit investment trusts and other available-for-sale securities. See Note 13 for additional information. There were no material other-than-temporary impairments in 2008, 2007 or 2006.

13. FAIR VALUE DISCLOSURES

A. DEBT AND INVESTMENTS

PROGRESS ENERGY

DEBT

The carrying amount of our long-term debt, including current maturities, was $10.659 billion and $9.614 billion at December 31, 2008 and 2007, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $11.260 billion and $9.897 billion at December 31, 2008 and 2007, 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 the Utilities' nuclear plants (See Note 4D). These nuclear decommissioning trust funds are primarily invested in stocks, bonds and cash equivalents classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at fair value. 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 fair value. Our available-for-sale securities at December 31, 2008 and 2007 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2008 **(in millions)**	**Book Value**	**Unrealized Losses**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$518**	**$(93)**	**$134**	**$559**
Debt securities	**478**	**(27)**	**15**	**466**
Cash equivalents	**114**	**–**	**–**	**114**
Total	**$1,110**	**$(120)**	**$149**	**$1,139**

2007 (in millions)	Book Value	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$475	$(10)	$354	$819
Debt securities	578	(4)	11	585
Cash equivalents	18	–	–	18
Total	$1,071	$(14)	$365	$1,422

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Under GAAP, such securities are considered to be impaired if they are in a loss position. Due to the ratemaking treatment applicable to nuclear decommissioning (See Note 12B), gains and losses on the nuclear decommissioning trusts accrue to the benefit or detriment of ratepayers and are included in the determination of regulatory assets and liabilities (See Note 7A), with no earnings impact. Therefore, the tables above include the book value and unrealized gains and losses for the nuclear decommissioning trusts based on the original cost of the trust investments; $118 million of the unrealized losses and $148 million of the unrealized gains for 2008 and all unrealized losses and gains for 2007 relate to the nuclear decommissioning trusts.

The aggregate fair value of investments that related to the 2008 and 2007 unrealized losses were $374 million and $243 million, respectively.

At December 31, 2008, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$2
Due after one through five years	183
Due after five through 10 years	126
Due after 10 years	155
Total	$466

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)	**2008**	2007	2006
Proceeds	**$1,092**	$1,334	$2,547
Realized gains	**29**	35	33
Realized losses	**86**	23	19

Previously, we invested available cash balances in various financial instruments, such as tax-exempt debt securities (See Note 12A). For the years ended December 31, 2007 and 2006, our proceeds from the sale of these securities were $399 million and $1.7 billion, respectively. For the year ended December 31, 2008, our proceeds were primarily related to nuclear decommissioning trusts. Some of our benefit investment trusts are managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2008, 2007 and 2006 for investments in these benefit investment trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2008 and 2007, 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 $3.509 billion and $3.483 billion at December 31, 2008 and 2007, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.690 billion and $3.545 billion at December 31, 2008 and 2007, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 4D). 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 fair value. 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 fair value. PEC's available-for-sale securities at December 31, 2008 and 2007 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2008 **(in millions)**	**Book Value**	**Unrealized Losses**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$314**	**$(55)**	**$75**	**$334**
Debt securities	**249**	**(10)**	**11**	**250**
Cash equivalents	**105**	**–**	**–**	**105**
Total	**$668**	**$(65)**	**$86**	**$689**

2007 (in millions)	Book Value	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$262	$(6)	$191	$447
Debt securities	344	(3)	6	347
Cash equivalents	11	–	–	11
Total	$617	$(9)	$197	$805

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Under GAAP, such securities are considered to be impaired if they are in a loss position. Due to the ratemaking treatment applicable to nuclear decommissioning (See Note 12B), gains and losses on the nuclear decommissioning trusts accrue to the benefit or detriment of ratepayers and are included in the determination of regulatory assets and liabilities (See Note 7A), with no earnings impact. Therefore, the tables above include the book value and unrealized gains and losses for the nuclear decommissioning trusts based on the original cost of the trust investments; all of the unrealized losses and gains for 2008 and 2007 relate to the nuclear decommissioning trusts.

The aggregate fair value of investments that related to the 2008 and 2007 unrealized losses were $191 million and $166 million, respectively.

At December 31, 2008, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$2
Due after one through five years	142
Due after five through 10 years	57
Due after 10 years	49
Total	$250

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)	**2008**	2007	2006
Proceeds	**$579**	$609	$995
Realized gains	**12**	12	21
Realized losses	**48**	13	10

Previously, PEC invested available cash balances in various financial instruments, such as tax-exempt debt securities (See Note 12A). For the year ended December 31, 2006, PEC's proceeds from the sale of these securities were $531 million. For the years ended December 31, 2008 and 2007, PEC's proceeds were primarily related to nuclear decommissioning trusts. 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, 2008, PEC did not have any other securities. At December 31, 2007, 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 $4.182 billion and $3.218 billion at December 31, 2008 and 2007, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $4.546 and $3.239 billion at December 31, 2008 and 2007, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 4D). 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 fair value. PEF's available-for-sale securities at December 31, 2008 and 2007 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2008				
(in millions)	**Book Value**	**Unrealized Losses**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$204**	**$(38)**	**$59**	**$225**
Debt securities	**189**	**(15)**	**3**	**177**
Cash equivalents	**9**	**–**	**–**	**9**
Total	**$402**	**$(53)**	**$62**	**$411**
2007				
(in millions)	Book Value	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$213	$(4)	$163	$372
Debt securities	194	(1)	5	198
Cash equivalents	7	–	–	7
Total	$414	$(5)	$168	$577

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Under GAAP, such securities are considered to be impaired if they are in a loss position. Due to the ratemaking treatment applicable to nuclear decommissioning (See Note 12B), gains and losses on the nuclear decommissioning trusts accrue to the benefit or detriment of ratepayers and are included in the determination of regulatory assets and liabilities (See Note 7A), with no earnings impact. Therefore, the tables above include the book value and unrealized gains and losses for the nuclear decommissioning trusts based on the original cost of the trust investments; all of the unrealized losses and gains for 2008 and 2007 relate to the nuclear decommissioning trusts.

The aggregate fair value of investments that related to the 2008 and 2007 unrealized losses were $165 million and $77 million, respectively.

At December 31, 2008, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$--
Due after one through five years	34
Due after five through 10 years	58
Due after 10 years	85
Total	$177

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)	**2008**	2007	2006
Proceeds	**$394**	$535	$509
Realized gains	**16**	22	12
Realized losses	**36**	9	8

Previously, PEF invested available cash balances in various financial instruments, such as tax-exempt debt securities (See Note 12A). For the years ended December 31, 2007 and 2006, PEF's proceeds from the sale of these securities were $329 million and $235 million, respectively. For the year ended December 31, 2008, all of PEF's proceeds were related to nuclear decommissioning trusts. 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, 2008, PEF did not have any other securities. At December 31, 2007, PEF's other securities had no investments in a continuous loss position for greater than 12 months.

B. FAIR VALUE MEASUREMENTS

In September 2006, the FASB issued SFAS No.157, which defines fair value, establishes a framework for measuring fair value under GAAP, and requires enhanced disclosures about assets and liabilities carried at fair value. SFAS No. 157 also establishes a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. In February 2008, the FASB issued FSP No. FAS 157-2, "Effective Date of FASB Statement No. 157," which delayed for us the effective date of SFAS No. 157 until January 1, 2009, for all nonfinancial assets and nonfinancial liabilities, except for those recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

We implemented SFAS No. 157 as of January 1, 2008, for all recurring financial assets and liabilities. The adoption of SFAS No. 157 for recurring financial assets and liabilities did not have a material impact on our or the Utilities' financial position or results of operations. We utilized the deferral provision of FSP No. FAS 157-2 for all nonrecurring nonfinancial assets and liabilities within its scope. Major categories of our assets and liabilities to which the deferral applies include reporting units and long-lived asset groups measured at fair value for impairment purposes, AROs initially recognized at fair value, and nonfinancial liabilities for exit and disposal costs and indemnifications initially measured at fair value. The January 1, 2009, adoption of SFAS No. 157 for nonrecurring nonfinancial assets and liabilities did not have a material impact on our or the Utilities' financial position or results of operations.

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). SFAS No. 157 permits the use of a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient and requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. SFAS No. 157 requires that valuation techniques maximize the use of observable inputs and minimize the use of unobservable inputs.

SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

> Level 1 – The pricing inputs are unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities.
>
> Level 2 – The pricing inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 2 includes financial instruments valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives, such as over-the-counter forwards, swaps and options; certain marketable debt securities; and financial instruments traded in less than active markets.
>
> Level 3 – The pricing inputs include significant inputs generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments may include longer-term instruments that extend into periods where quoted prices or other observable inputs are not available.

The following tables set forth by level within the fair value hierarchy our and the Utilities' financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS No. 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Progress Energy

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Commodity derivatives	$–	$10	$–	$10
Nuclear decommissioning trust funds	592	497	–	1,089
Other marketable securities	16	38	–	54
Total assets	$608	$545	$–	$1,153
Liabilities				
Commodity derivatives	$–	$(647)	$(41)	$(688)
Interest rate derivatives	–	(65)	–	(65)
CVO derivatives	–	(34)	–	(34)
Total liabilities	$–	$(746)	$(41)	$(787)

PEC

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds	$368	$304	$–	$672
Other marketable securities	2	–	–	2
Total assets	$370	$304	$–	$674
Liabilities				
Commodity derivatives	$–	$(77)	$(22)	$(99)
Interest rate derivatives	–	(35)	–	(35)
Total liabilities	$–	$(112)	$(22)	$(134)

PEF

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Commodity derivatives	$–	$10	$–	$10
Nuclear decommissioning trust funds	224	193	–	417
Other marketable securities	1	–	–	1
Total assets	$225	$203	$–	$428
Liabilities				
Commodity derivatives	$–	$(570)	$(19)	$(589)

The determination of the fair values above incorporates various factors required under SFAS No. 157, including risks of nonperformance by us or our counterparties. Such risks consider not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits or letters of credit), but also the impact of our and the Utilities' credit risk on our liabilities.

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

Nuclear decommissioning trust funds reflect the assets of the Utilities' nuclear decommissioning trusts, as discussed in Note 12A. The assets of the trusts are invested primarily in exchange-traded equity securities (classified within Level 1) and marketable debt securities, most of which are valued using Level 1 inputs for similar instruments, and are classified within Level 2.

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

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

The following tables set forth a reconciliation of changes in the fair value of our and the Utilities' commodity derivatives classified as Level 3 in the fair value hierarchy for the 12 months ended December 31, 2008.

Progress Energy	
(in millions)	
Derivatives, net at January 1, 2008	$26
Total gains (losses), realized and unrealized	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(102)
Purchases, issuances and settlements, net	–
Transfers out of Level 3, net	35
Derivatives, net at December 31, 2008	$(41)

PEC	
(in millions)	
Derivatives, net at January 1, 2008	$6
Total gains (losses), realized and unrealized	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(32)
Purchases, issuances and settlements, net	–
Transfers out of Level 3, net	4
Derivatives, net at December 31, 2008	$(22)

PEF	
(in millions)	
Derivatives, net at January 1, 2008	$20
Total gains (losses), realized and unrealized:	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(70)
Purchases, issuances and settlements, net	–
Transfers out of Level 3, net	31
Derivatives, net at December 31, 2008	$(19)

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

Transfers out of Level 3 represent existing assets or liabilities previously classified as Level 3 for which the lowest significant input became observable during the period.

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, "Accounting for Income Taxes" (SFAS No. 109), is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount that, in our judgment, is greater than 50 percent likely to be realized.

PROGRESS ENERGY

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

(in millions)	**2008**	2007
Deferred income tax assets		
ARO liability	**$264**	$146
Compensation accruals	**100**	101
Derivative instruments	**286**	–
Environmental remediation liability	**21**	32
Income taxes refundable through future rates	**111**	324
Pension and other postretirement benefits	**544**	306
Unbilled revenue	**61**	59
Other	**170**	122
Federal income tax credit carry forward	**802**	836
State net operating loss carry forward (net of federal expense)	**64**	87
Valuation allowance	**(55)**	(79)
Total deferred income tax assets	**2,368**	1,934
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,665)**	(1,482)
Deferred fuel recovery	**(186)**	(64)
Deferred nuclear cost recovery	**(73)**	–
Derivative instruments	–	(59)
Income taxes recoverable through future rates	**(959)**	(317)
Investments	**(6)**	(99)
Prepaid pension costs	–	(18)
Other	**(62)**	(56)
Total deferred income tax liabilities	**(2,951)**	(2,095)
Total net deferred income tax liabilities	**$(583)**	$(161)

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

(in millions)	**2008**	2007
Current deferred income tax assets, included in prepayments and other current assets	**$96**	$45
Noncurrent deferred income tax assets, included in other assets and deferred debits	**32**	65
Current deferred income tax liabilities, included in other current liabilities	**(1)**	(5)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(710)**	(266)
Total net deferred income tax liabilities	**$(583)**	$(161)

At December 31, 2008, the federal income tax credit carry forward includes $802 million of alternative minimum tax credits that do not expire.

At December 31, 2008, we had gross state net operating loss carry forwards of $1.5 billion that will expire during the period 2009 through 2028.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We had a net reduction of $24 million in our valuation allowances during 2008:

- We increased our valuation allowances by $12 million during 2008. Additional valuation allowances of $9 million were recorded related to PVI's 2007 state net operating loss carry forward. Additional valuation allowances of $3 million were recorded to fully offset state net operating loss and state capital loss carry forwards generated during 2008.

- We reduced our valuation allowances and deferred income tax assets by $36 million during 2008 due to the ceasing of business operations in various state taxing jurisdictions. The $36 million of valuation allowances were previously recorded to fully offset $36 million of state deferred income tax assets related to our terminal, coal mining and synthetic fuel businesses. During 2008, we sold our terminal and remaining coal mining businesses and dissolved our synthetic fuel businesses, which caused us to cease business operations in various state taxing jurisdictions. We believe that we will not realize the deferred income tax assets for those jurisdictions, and accordingly we reduced our total deferred income tax assets and corresponding valuation allowances by $36 million, which had no net impact on total deferred income tax assets.

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

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

	2008	2007	2006
Effective income tax rate	**33.7%**	32.3%	37.5%
State income taxes, net of federal benefit	**(3.8)**	(2.8)	(3.5)
Investment tax credit amortization	**1.0**	1.1	1.3
Employee stock ownership plan dividends	**1.0**	1.1	1.3
Domestic manufacturing deduction	**0.3**	1.0	0.4
AFUDC equity	**2.5**	0.7	(0.1)
Other differences, net	**0.3**	1.6	(1.9)
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)	**2008**	2007	2006
Current – federal	**$38**	$285	$394
– state	**12**	36	70
Deferred – federal	**305**	13	(94)
– state	**49**	11	(17)
Investment tax credit	**(12)**	(12)	(12)
State net operating loss carry forward	**(6)**	1	(2)
Beginning-of-the-year valuation allowance change	**9**	–	–
Total income tax expense	**$395**	$334	$339

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

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

- Taxes related to discontinued operations recorded net of tax for 2008, 2007 and 2006, which are presented separately in Notes 3A through 3G.

- Taxes related to other comprehensive income recorded net of tax for 2008, 2007 and 2006, which are presented separately in the Consolidated Statements of Comprehensive Income.

- Current tax benefit of $6 million, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $3 million, which was recorded in common stock during 2006, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2008.

- Taxes of $2 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48) on January 1, 2007.

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

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

We and our subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. During 2007, we closed federal tax years 1998 to 2003. Our open federal tax years are from 2004 forward and our open state tax years in our major jurisdictions are generally from 2003 forward. The Internal Revenue Service (IRS) is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when those examinations will be completed. We are not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2009.

We include interest expense related to unrecognized tax benefits in interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2008 and 2007, the net interest expense related to unrecognized tax benefits was $4 million and $1 million, respectively, of which a respective $1 million and $15 million expense component was deferred as a regulatory asset by PEF, which is amortized as a charge to interest expense over a three-year period or less. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2008, less than $1 million was recorded for penalties related to unrecognized tax benefits. During 2007, there were no penalties related to unrecognized tax benefits. At December 31, 2008 and 2007, we had accrued $27 million and $23 million, respectively, for interest and penalties, which are included in other liabilities and deferred credits on the Consolidated Balance Sheets.

PEC

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

(in millions)	2008	2007
Deferred income tax assets		
ARO liability	**$244**	$140
Compensation accruals	**52**	55
Derivative instruments	**64**	4
Income taxes refundable through future rates	**10**	83
Pension and other postretirement benefits	**262**	166
Unbilled revenue	**18**	18
Other	**38**	36
Federal income tax credit carry forward	**–**	1
Total deferred income tax assets	**688**	503
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,162)**	(1,013)
Deferred fuel recovery	**(132)**	(60)
Income taxes recoverable through future rates	**(451)**	(218)
Investments	**(8)**	(74)
Other	**(12)**	(7)
Total deferred income tax liabilities	**(1,765)**	(1,372)
Total net deferred income tax liabilities	**$(1,077)**	$(869)

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

(in millions)	2008	2007
Current deferred income tax assets, included in prepayments and other current assets	**$–**	$26
Current deferred income tax liabilities, included in other current liabilities	**(5)**	–
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(1,072)**	(895)
Total net deferred income tax liabilities	**$(1,077)**	$(869)

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

	2008	2007	2006
Effective income tax rate	**35.8%**	37.1%	36.7%
State income taxes, net of federal benefit	**(2.7)**	(2.3)	(2.3)
Investment tax credit amortization	**0.7**	0.7	0.8
Domestic manufacturing deduction	**0.5**	1.1	0.6
Other differences, net	**0.7**	(1.6)	(0.8)
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)	**2008**	2007	2006
Current – federal	**$87**	$235	$285
– state	**7**	19	39
Deferred – federal	**181**	34	(42)
– state	**29**	13	(11)
Investment tax credit	**(6)**	(6)	(6)
Total income tax expense	**$298**	$295	$265

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

- Taxes related to other comprehensive income recorded net of tax for 2008, 2007 and 2006, which are presented separately in the Consolidated Statements of Comprehensive Income.

- Current tax benefit of $3 million, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $1 million, which was recorded in common stock during 2006, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2008.

- Taxes of $6 million that reduced retained earnings, due to the cumulative effect of adopting the provisions of FIN 48 on January 1, 2007.

PEC and each of its wholly owned subsidiaries have entered into the Tax Agreement with the Parent (See Note 1D). PEC's intercompany tax receivable was approximately $74 million at December 31, 2008. PEC's intercompany tax payable was approximately $27 million at December 31, 2007.

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

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

We file consolidated federal and state income tax returns that include PEC. In addition, PEC files stand-alone tax returns in various state jurisdictions. During 2007, we closed federal tax years 1998 to 2003. PEC's open federal tax years are from 2004 forward and

PEC's open state tax years in our major jurisdictions are generally from 2003 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. PEC cannot predict when those examinations will be completed. PEC is not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2009.

PEC includes interest expense related to unrecognized tax benefits in interest charges and includes penalties in other, net on the Consolidated Statements of Income. During 2008 and 2007, the interest benefit recorded related to unrecognized tax benefits was $1 million and $4 million, respectively, and there were no penalties recorded related to unrecognized tax benefits. At December 31, 2008 and 2007, PEC had accrued $7 million and $8 million, respectively, for interest and penalties, which is included in other liabilities and deferred credits on the Consolidated Balance Sheets.

PEF

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

(in millions)	**2008**	2007
Deferred income tax assets		
Compensation accruals	**$23**	$21
Derivative instruments	**222**	–
Environmental remediation liability	**14**	18
Income taxes refundable through future rates	**54**	190
Pension and other postretirement benefits	**192**	142
Reserve for storm damage	**54**	25
Unbilled revenue	**43**	41
Other	**64**	56
Total deferred income tax assets	**666**	493
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(490)**	(451)
Deferred fuel recovery	**(54)**	(4)
Deferred nuclear cost recovery	**(73)**	–
Derivative instruments	**–**	(64)
Income taxes recoverable through future rates	**(508)**	(99)
Investments	**(3)**	(63)
Prepaid pension costs	**–**	(86)
Other	**(36)**	(33)
Total deferred income tax liabilities	**(1,164)**	(800)
Total net deferred income tax liabilities	**$(498)**	$(307)

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

(in millions)	**2008**	2007
Current deferred income tax assets, included in prepayments and other current assets	**$74**	$39
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(572)**	(346)
Total net deferred income tax liabilities	**$(498)**	$(307)

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

	2008	2007	2006
Effective income tax rate	**32.0%**	31.2%	37.0%
State income taxes, net of federal benefit	**(3.1)**	(3.3)	(3.6)
Investment tax credit amortization	**1.1**	1.3	1.2
Domestic manufacturing deduction	**0.2**	0.8	0.3
AFUDC equity	**5.4**	2.6	0.7
Other differences, net	**(0.6)**	2.4	(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)	**2008**	2007	2006
Current – federal	**$39**	$160	$207
– state	**12**	28	34
Deferred – federal	**121**	(33)	(36)
– state	**15**	(5)	(6)
Investment tax credit	**(6)**	(6)	(6)
Total income tax expense	**$181**	$144	$193

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

- Taxes related to other comprehensive income recorded net of tax for 2008, 2007 and 2006, which are presented separately in the Statements of Comprehensive Income.
- Less than $1 million of current tax benefit, which was recorded in common stock during 2007 and 2006, related to excess tax deductions resulting from vesting of restricted stock awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2008.
- Taxes of less than $1 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting the provisions of FIN 48 on January 1, 2007.

PEF has entered into the Tax Agreement with the Parent (See Note 1D). PEF's intercompany tax receivable was approximately $47 million and $41 million at December 31, 2008 and 2007, respectively.

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

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

We file consolidated federal and state income tax returns that include PEF. During 2007, we closed federal tax years 1998 to 2003. PEF's open federal tax years are from 2004 forward and PEF's open state tax years are generally from 2003 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. PEF cannot predict when those examinations will be completed. PEF is not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2009.

Pursuant to a regulatory order, PEF records interest expense related to unrecognized tax benefits as a regulatory asset, which is amortized over a three-year period or less, with the amortization included in interest charges on the Statements of Income. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense on the Statement of Income. Penalties are included in other, net on the Statements of Income. During 2008 and 2007, interest expense recorded as a regulatory asset was $1 million and $15 million, respectively, and there were no penalties recorded related to unrecognized tax benefits. At December 31, 2008 and 2007, PEF had accrued $19 million and $18 million, respectively, for interest and penalties, which is included in other liabilities and deferred credits on the Balance Sheets.

15. CONTINGENT VALUE OBLIGATIONS

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

During the year ended December 31, 2008, a $6 million deposit was made into the CVO trust for the CVO holders' share of the disposition proceeds from the sale of one of the Earthco synthetic fuel facilities (See Note 3J). Disposition proceeds payments will not generally be made to CVO holders until the termination of all indemnity obligations under the purchase and sale agreement related to the disposition. During 2007, a $5 million deposit was made into a CVO trust for the net after-tax cash flows generated by the four

Earthco synthetic fuels facilities in 2004. Deposits into the trust will be classified as a restricted cash asset until the applicable tax years are closed, at which time a payment will be disbursed to the CVO holders. Future payments will include principal and interest earned during the investment period net of expenses deducted. The interest earned on the payments held in trust for 2008 and 2007 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheet at December 31, 2008.

16. BENEFIT PLANS

A. POSTRETIREMENT BENEFITS

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

COSTS OF BENEFIT PLANS

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

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

The components of the net periodic benefit cost for the years ended December 31 were:

Progress Energy

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2008**	2007	2006	**2008**	2007	2006
Service cost	**$46**	$46	$45	**$8**	$7	$9
Interest cost	**128**	123	117	**34**	32	33
Expected return on plan assets	**(170)**	(155)	(148)	**(6)**	(6)	(6)
Amortization of actuarial loss[(a)]	**8**	15	18	**1**	2	4
Other amortization, net [(a)]	**2**	2	–	**5**	5	5
Net periodic cost	**$14**	$31	$32	**$42**	$40	$45

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

We and the Utilities adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)" (SFAS No. 158), as of December 31, 2006. SFAS No. 158 amended prior accounting requirements for pension and OPEB plans. Prior to the implementation of SFAS No. 158, other comprehensive income (OCI) reflected minimum pension adjustments related to our pension plans. Our pre-tax minimum pension adjustment recognized as a component of OCI was a net actuarial gain of $78 million for the year ended December 31, 2006. No amounts related to our OPEB plans were recognized as a component of OCI for the year ended December 31, 2006. The tables below provide a summary of amounts recognized in other comprehensive income for 2008 and 2007 and other comprehensive income reclassification adjustments for amounts included in net income for 2008 and 2007. The tables also include comparable items that affected regulatory assets of PEC and PEF. Refer to the PEC and PEF sections below for more information with regard to these regulatory assets.

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

PEC

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2008**	2007	2006	**2008**	2007	2006
Service cost	**$23**	$23	$22	**$5**	$5	$4
Interest cost	**58**	56	52	**17**	15	17
Expected return on plan assets	**(66)**	(60)	(59)	**(4)**	(4)	(4)
Amortization of actuarial loss	**6**	12	11	**–**	–	2
Other amortization, net	**2**	2	1	**1**	1	1
Net periodic cost	**$23**	$33	$27	**$19**	$17	$20

No amounts related to PEC's OPEB plans were recognized as a component of OCI for the year ended December 31, 2006. PEC's pre-tax minimum pension adjustment recognized as a component of OCI for the year ended December 31, 2006, was a net actuarial gain of $59 million. In conjunction with the implementation of SFAS No. 158, amounts that would otherwise be recorded in OCI are recorded as adjustments to regulatory assets consistent with the recovery of the related costs through the ratemaking process. The tables below provide a summary of amounts recognized in regulatory assets for 2008 and 2007 and amounts amortized from regulatory assets to net income for 2008 and 2007.

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

PEF

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2008**	2007	2006	**2008**	2007	2006
Service cost	**$17**	$16	$16	**$2**	$2	$3
Interest cost	**53**	52	49	**14**	14	14
Expected return on plan assets	**(90)**	(84)	(78)	**(1)**	(1)	(1)
Amortization of actuarial loss	**1**	1	3	**1**	2	1
Other amortization, net	**(1)**	(1)	(1)	**3**	3	4
Net periodic (benefit) cost	**$(20)**	$(16)	$(11)	**$19**	$20	$21

No amounts related to PEF's OPEB or pension plans were recorded as a component of OCI for the years ended December 31, 2008, 2007 and 2006. Amounts that would otherwise be recorded in OCI are recorded as adjustments to regulatory assets consistent with the recovery of the related costs through the ratemaking process. The tables below provides a summary of amounts recognized in regulatory assets for 2008 and 2007 and amounts amortized from regulatory assets to net income for 2008 and 2007.

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

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

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	**2008**	2007	2006
Discount rate	**6.20%**	5.95%	5.65%	**6.20%**	5.95%	5.65%
Rate of increase in future compensation						
Bargaining	**4.25%**	4.25%	3.50%	–	–	–
Supplementary plans	**5.25%**	5.25%	5.25%	–	–	–
Expected long-term rate of return on plan assets	**9.00%**	9.00%	9.00%	**8.10%**	7.70%	8.30%

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

The expected long-term rates of return on plan assets were determined by considering long-term historical returns for the plans and long-term projected returns based on the plans' target asset allocation. For all pension plan assets and a substantial portion of OPEB plan assets, those benchmarks support an expected long-term rate of return between 9.0% and 9.5%. The Progress Registrants used an expected long-term rate of 9.0%, the low end of the range, for 2008, 2007 and 2006.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

SFAS No. 158 requires us to recognize in our statement of financial condition the funded status of our pension and other postretirement benefit plans, measured as the difference between the fair value of the plan assets and the benefit obligation as of the end of the fiscal year.

Reconciliations of the changes in the Progress Registrants' benefit obligations and the funded status as of December 31, 2008 and 2007 are presented in the tables below, with each table followed by related supplementary information.

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Projected benefit obligation at January 1	**$2,142**	$2,123	**$541**	$628
Service cost	**46**	46	**8**	7
Interest cost	**128**	123	**34**	32
Benefit payments	**(127)**	(131)	**(35)**	(30)
Plan amendment	**42**	8	–	–
Actuarial loss (gain)	**3**	(27)	**60**	(96)
Obligation at December 31	**2,234**	2,142	**608**	541
Fair value of plan assets at December 31	**1,285**	1,996	**52**	75
Funded status	**$(949)**	$(146)	**$(556)**	$(466)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $2.234 billion and $463 million at December 31, 2008 and 2007, respectively. Those plans had accumulated benefit obligations totaling $2.196 billion and $422 million at December 31, 2008 and 2007, respectively, and plan assets of $1.285 billion and $269 million at December 31, 2008 and 2007, respectively. The total accumulated benefit obligation for pension plans was $2.196 billion and $2.100 billion at December 31, 2008 and 2007, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Noncurrent assets	**$–**	$48	**$–**	$–
Current liabilities	**(10)**	(10)	**(1)**	–
Noncurrent liabilities	**(939)**	(184)	**(555)**	(466)
Funded status	**$(949)**	$(146)	**$(556)**	$(466)

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)	**2008**	2007	**2008**	2007
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	**$87**	$22	**$–**	$(9)
Other, net	**11**	6	**–**	1
Recognized in regulatory assets, net				
Net actuarial loss	**865**	136	**97**	25
Other, net	**62**	28	**18**	23
Total not yet recognized as a component of net periodic cost[(a)]	**$1,025**	$192	**$115**	$40

(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 2009.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss [(a)]	$48	$4
Amortization of other, net[(a)]	6	5

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

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Projected benefit obligation at January 1	**$980**	$952	**$257**	$330
Service cost	**23**	23	**5**	5
Interest cost	**58**	56	**17**	15
Plan amendment	**31**	6	**–**	–
Benefit payments	**(55)**	(60)	**(15)**	(12)
Actuarial (gain) loss	**(12)**	3	**48**	(81)
Obligation at December 31	**1,025**	980	**312**	257
Fair value of plan assets at December 31	**521**	805	**22**	44
Funded status	**$(504)**	$(175)	**$(290)**	$(213)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $1.025 billion and $980 million at December 31, 2008 and 2007, respectively. Those plans had accumulated benefit obligations totaling $1.021 billion and $974 million at December 31, 2008 and 2007, respectively, and plan assets of $521 million and $805 million at December 31, 2008 and 2007, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Current liabilities	**$(2)**	$(2)	**$ –**	$ –
Noncurrent liabilities	**(502)**	(173)	**(290)**	(213)
Funded status	**$(504)**	$(175)	**$(290)**	$(213)

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)	**2008**	2007	**2008**	2007
Recognized in regulatory assets				
Net actuarial loss (gain)	**$407**	$104	**$54**	$(12)
Other, net	**57**	29	**4**	5
Total not yet recognized as a component of net periodic cost	**$464**	$133	**$58**	$(7)

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2009.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	$8	$3
Amortization of other, net	5	1

PEF

(in millions)	Pension Benefits 2008	Pension Benefits 2007	Other Postretirement Benefits 2008	Other Postretirement Benefits 2007
Projected benefit obligation at January 1	**$881**	$880	**$245**	$246
Service cost	**17**	16	**2**	2
Interest cost	**53**	52	**14**	14
Plan amendment	**5**	1	**–**	–
Benefit payments	**(58)**	(57)	**(18)**	(16)
Actuarial loss (gain)	**16**	(11)	**5**	(1)
Obligation at December 31	**914**	881	**248**	245
Fair value of plan assets at December 31	**650**	1,026	**27**	26
Funded status	**$(264)**	$145	**$(221)**	$(219)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $914 million and $345 million at December 31, 2008 and 2007, respectively. Those plans had accumulated benefit obligations totaling $884 million and $313 million at December 31, 2008 and 2007, respectively, and plan assets of $650 million and $269 million at December 31, 2008 and 2007, respectively. The total accumulated benefit obligation for pension plans was $884 million and $849 million at December 31, 2008 and 2007, respectively.

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

(in millions)	Pension Benefits 2008	Pension Benefits 2007	Other Postretirement Benefits 2008	Other Postretirement Benefits 2007
Noncurrent assets	**$–**	$221	**$ –**	$ –
Current liabilities	**(3)**	(3)	**–**	–
Noncurrent liabilities	**(261)**	(73)	**(221)**	(219)
Funded status	**$(264)**	$145	**$(221)**	$(219)

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

(in millions)	Pension Benefits 2008	Pension Benefits 2007	Other Postretirement Benefits 2008	Other Postretirement Benefits 2007
Recognized in regulatory assets, net				
Net actuarial loss	**$458**	$32	**$43**	$37
Other, net	**5**	(1)	**14**	18
Total not yet recognized as a component of net periodic cost	**$463**	$31	**$57**	$55

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2009.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	$36	$2
Amortization of other, net	–	4

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

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	**2008**	2007
Discount rate	**6.30%**	6.20%	**6.20%**	6.20%
Rate of increase in future compensation				
Bargaining	**4.25%**	4.25%	–	–
Supplementary plans	**5.25%**	5.25%	–	–
Initial medical cost trend rate for pre-Medicare Act benefits	–	–	**9.00%**	9.00%
Initial medical cost trend rate for post-Medicare Act benefits	–	–	**9.00%**	9.00%
Ultimate medical cost trend rate	–	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	–	–	**2016**	2015

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	$3	$2	$1
Effect on postretirement benefit obligation	37	19	15
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(2)	(1)	(1)
Effect on postretirement benefit obligation	(30)	(16)	(12)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our, PEC's and PEF's employer contributions for 2008 include contributions directly to pension plan assets of $33 million, $24 million and less than $1 million, respectively, and for 2007 include contributions directly to pension plan assets of $63 million, $33 million and $15 million, respectively. Substantially all of the remaining employer contributions represent benefit payments made directly from the Progress Registrants' assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the cost after participant contributions. Participant contributions represent approximately 20 percent of gross benefit payments for Progress Energy, 25 percent for PEC and 15 percent for PEF. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2008 and 2007, the subsidies totaled $3 million for us, $1 million for PEC and $2 million for PEF.

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

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Fair value of plan assets at January 1	**$1,996**	$1,836	**$75**	$74
Actual return on plan assets	**(627)**	219	**(16)**	7
Benefit payments	**(127)**	(131)	**(35)**	(30)
Employer contributions	**43**	72	**28**	24
Fair value of plan assets at December 31	**$1,285**	$1,996	**$52**	$75

PEC

(in millions)	Pension Benefits 2008	Pension Benefits 2007	Other Postretirement Benefits 2008	Other Postretirement Benefits 2007
Fair value of plan assets at January 1	**$805**	$741	**$44**	$45
Actual return on plan assets	**(255)**	89	**(14)**	5
Benefit payments	**(55)**	(60)	**(15)**	(12)
Employer contributions	**26**	35	**7**	6
Fair value of plan assets at December 31	**$521**	$805	**$22**	$44

PEF

(in millions)	Pension Benefits 2008	Pension Benefits 2007	Other Postretirement Benefits 2008	Other Postretirement Benefits 2007
Fair value of plan assets at January 1	**$1,026**	$952	**$26**	$24
Actual return on plan assets	**(321)**	113	**–**	1
Benefit payments	**(58)**	(57)	**(18)**	(16)
Employer contributions	**3**	18	**19**	17
Fair value of plan assets at December 31	**$650**	$1,026	**$27**	$26

The asset allocation for the benefit plans at the end of 2008 and 2007 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	2009	**2008**	2007
Equity – domestic	40%	**39%**	42%
Equity – international	20%	**20%**	25%
Debt – domestic	10%	**10%**	11%
Debt – international	15%	**16%**	12%
Other	15%	**15%**	10%
Total	100%	**100%**	100%

	Other Postretirement Benefits		
Progress Energy	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2009	**2008**	2007
Equity – domestic	20%	**18%**	28%
Equity – international	10%	**10%**	16%
Debt – domestic	50%	**57%**	41%
Debt – international	10%	**8%**	8%
Other	10%	**7%**	7%
Total	100%	**100%**	100%

PEC	Target Allocations	Percentage of Plan Assets	
Asset Category	2009	**2008**	2007
Equity – domestic	40%	**39%**	42%
Equity – international	20%	**20%**	25%
Debt – domestic	10%	**10%**	11%
Debt – international	15%	**16%**	12%
Other	15%	**15%**	10%
Total	100%	**100%**	100%

PEF	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2009	**2008**	2007
Debt – domestic	100%	**100%**	100%

For pension plan assets and a substantial portion of OPEB plan assets, the Progress Registrants set target allocations among asset classes to provide broad diversification to protect against large investment losses and excessive volatility, while recognizing the importance of offsetting the impacts of benefit cost escalation. In addition, external investment managers who have complementary investment philosophies and approaches are employed to manage the assets. Tactical shifts (plus or minus 5 percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2009, we expect to make at least $130 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 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $154, $157, $158, $167, $169 and $923, respectively. The expected benefit payments for the OPEB plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $40, $43, $45, $48, $50 and $268, 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 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $4, $4, $5, $5, $6 and $40, respectively.

In 2009, PEC expects to make at least $75 million in contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $78, $79, $79, $83, $82 and $445, respectively. The expected benefit payments for the OPEB plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $17, $19, $21, $23, $24, and $139, 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 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $2, $2, $2, $3, $3 and $21, respectively.

In 2009, PEF expects to make at least $55 million in contributions directly to pension plan assets and expects to make $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $58, $59, $60, $62, $63 and $354, respectively. The expected benefit payments for the OPEB plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $20, $21, $21, $22, $22 and $109, 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 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $2, $2, $2, $2, $3 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 and financial reviews using a combination of financial analysis and publicly available credit ratings of such counterparties. Potential nonperformance by counterparties is not expected to have a material effect on our financial position or results of operations.

As discussed in Note 15, in connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income (See Note 20). At December 31, 2008 and 2007, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million.

A. COMMODITY DERIVATIVES

GENERAL

Most of our physical commodity contracts are not derivatives 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, 2008 and 2007, the remaining liability was $7 million and $10 million, respectively.

DISCONTINUED OPERATIONS

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

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Note 3J, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate Ceredo in accordance with FIN 46R, but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. At December 31, 2007, the fair value of all of these contracts was recorded as a $234 million short-term derivative asset position, including $79 million at Ceredo. The fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet (See Note 5). We had a $108 million cash collateral liability related to these contracts at December 31, 2007, included in other current liabilities on the Consolidated Balance Sheet. As discussed in Note 3A, on October 12, 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts. Of this amount, $57 million was attributable to Ceredo of which $42 million was attributed to minority interest for the portion of the gain subsequent to the disposal of Ceredo.

Due to the divestitures of Gas and CCO, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts would be fulfilled and cash flow hedge accounting for the contracts was discontinued in 2006. For the year ended December 31, 2006, discontinued operations, net of tax on the Consolidated Statements of Income included $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges, and immaterial net gains and losses from other derivative instruments related to Gas and CCO.

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause. During the years ended December 31, 2008 and 2007, PEC recorded a net realized gain of $2 million and a net realized loss of $9 million, respectively. PEC's net realized loss was not material during the year ended December 31, 2006. During the years ended December 31, 2008, 2007 and 2006, PEF recorded a net realized gain of $172 million, a net realized loss of $46 million and a net realized gain of $39 million, respectively.

At December 31, 2008, the fair value of PEC's commodity derivative instruments was recorded as a $45 million short-term derivative liability position included in derivative liabilities and a $54 million long-term derivative liability position included in other liabilities and deferred credits on the PEC Consolidated Balance Sheet. At December 31, 2007, the fair value of such instruments was recorded as a $19 million long-term derivative asset position included in other assets and deferred debits and a $4 million short-term derivative liability position included in derivative liabilities on the PEC Consolidated Balance Sheet. Certain counterparties have held cash collateral with PEC in support of these instruments. PEC had an $18 million cash collateral asset included in prepayments and other current assets on the PEC Consolidated Balance Sheet at December 31, 2008, and no cash collateral position at December 31, 2007.

At December 31, 2008, the fair value of PEF's commodity derivative instruments was recorded as a $9 million short-term derivative asset position included in current derivative assets, a $1 million long-term derivative asset position included in derivative assets, a $380 million short-term derivative liability position included in current derivative liabilities, and a $209 million long-term derivative liability position included in derivative liabilities on the PEF Balance Sheet. At December 31, 2007, the fair value of such instruments was recorded as an $83 million short-term derivative asset position included in current derivative assets, a $100 million long-term derivative asset position included in derivative assets, a $38 million short-term derivative liability position included in current derivative liabilities, and a $9 million long-term derivative liability position included in derivative liabilities on the PEF Balance Sheet. Certain counterparties have posted or held cash collateral in support of these instruments. PEF had a $335 million cash collateral asset included in derivative collateral posted and a $12 million cash collateral liability included in other current liabilities on the PEF Balance Sheet at December 31, 2008, and no cash collateral position at December 31, 2007.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding some of these instruments is to hedge exposure to market risk associated with fluctuations in the price of power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. Realized gains and losses are recorded net as part of fleet vehicle costs. At December 31, 2008 and 2007, neither we nor the Utilities had material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities' results of operations for 2008, 2007 and 2006.

At December 31, 2008 and 2007, the amount recorded in our or the Utilities' accumulated other comprehensive income related to commodity cash flow hedges was not material.

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

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

CASH FLOW HEDGES

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

	Progress Energy		PEC		PEF	
(in millions)	**2008**	2007	**2008**	2007	**2008**	**2007**
Fair value of liabilities	**$(65)**	$(12)	**$(35)**	$(12)	$–	$–

The effective portion of gains and losses from interest rate cash flow hedges, including terminated hedges, is recorded in accumulated other comprehensive income, and amortized to net interest charges as the hedged transactions occur. The ineffective portion of interest rate cash flow hedges was not material to our or the Utilities' results of operations for 2008, 2007 and 2006.

The following table presents selected information related to interest rate cash flow hedges included in accumulated other comprehensive income at December 31, 2008:

(term in years/millions of dollars)	Progress Energy	PEC	PEF
Maximum term	Less than 1	Less than 1	–
Accumulated other comprehensive loss, net of tax[(a)]	$(56)	$(35)	$–
Portion expected to be reclassified to earnings during the next 12 months[(b)]	$(3)	$(2)	$–

(a) Includes amounts related to terminated hedges.

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

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

At December 31, 2008, the Parent had $200 million notional of interest rate cash flow hedges. During 2008, the Parent entered into a combined $200 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. In January 2009, the Parent entered into a $50 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

At December 31, 2008 and 2007, PEC had $250 million notional and $200 million notional, respectively, of interest rate cash flow hedges. In March 2008, all of PEC's 2007 forward starting swaps were terminated in conjunction with PEC's issuance of $325 million of First Mortgage Bonds, 6.30% Series due 2038. During 2008, PEC entered into a combined $250 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. All of PEC's 2008 forward starting swaps were terminated on January 12, 2009, in conjunction with PEC's issuance of $600 million of First Mortgage Bonds, 5.30% Series due 2019. After the January 2009 debt issuance, PEC entered into a $50 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

At December 31, 2008 and 2007, PEF had no outstanding interest rate cash flow hedge positions. During 2008, PEF entered into a combined $550 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. In June 2008, all of PEF's forward starting swaps were terminated in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. In January 2009, PEF entered into a $50 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At December 31, 2008 and 2007, neither we nor the Utilities had any outstanding positions in such contracts.

18. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2008, the Parent had issued $386 million of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheet.

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of the Public Utility Holding Company Act of 1935 (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 2008, 2007 and 2006 to PEC amounted to $194 million, $182 million and $188 million, respectively, and services provided to PEF were $160 million, $174 million and $165 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2008, 2007 and 2006 amounted to $44 million, $54 million and $34 million, respectively. Services provided by PEF to PEC during 2008, 2007 and 2006 amounted to $12 million, $10 million and $8 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 3.29%, 5.49% and 5.17% at December 31, 2008, 2007 and 2006, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Balance Sheets. PEC and PEF recorded insignificant interest expense related to the money pool for all the years presented.

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

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

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

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

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," as a separate business segment. The profit or loss of our reportable segments plus the profit or loss of Corporate and Other represents our total income from continuing operations.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for 2007 and 2006 transactions between PEF and businesses included in the Corporate and Other segment, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and businesses included in the Corporate and Other segment are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. The profits realized for 2007 and 2006 were not significant.

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

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2008					
Revenues					
Unaffiliated	$4,429	$4,730	$8	$ –	$9,167
Intersegment	–	1	361	(362)	–
Total revenues	4,429	4,731	369	(362)	9,167
Depreciation, amortization and accretion	518	306	15	–	839
Interest income	12	9	38	(35)	24
Total interest charges, net	207	208	259	(35)	639
Income tax expense (benefit)	298	181	(84)	–	395
Segment profit (loss)	531	383	(141)	–	773
Total assets	13,165	12,471	17,483	(13,246)	29,873
Capital and investment expenditures	939	1,601	33	(13)	2,560

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2007					
Revenues					
Unaffiliated	$4,385	$4,748	$ 20	$ –	$9,153
Intersegment	–	1	393	(394)	–
Total revenues	4,385	4,749	413	(394)	9,153
Depreciation, amortization and accretion	519	366	20	–	905
Interest income	21	9	55	(51)	34
Total interest charges, net	210	173	258	(53)	588
Income tax expense (benefit)	295	144	(105)	–	334
Segment profit (loss)	498	315	(120)	–	693
Total assets	11,955	10,063	16,356	(12,088)	26,286
Capital and investment expenditures	941	1,262	3	(2)	2,204

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2006					
Revenues					
Unaffiliated	$4,086	$4,638	$ –	$ –	$8,724
Intersegment	–	1	729	(730)	–
Total revenues	4,086	4,639	729	(730)	8,724
Depreciation, amortization and accretion	571	404	36	–	1,011
Interest income	25	15	85	(66)	59
Total interest charges, net	215	150	326	(67)	624
Income tax expense (benefit)	265	193	(119)	–	339
Segment profit (loss)	454	326	(229)	–	551
Total assets	11,999	8,648	15,394	(11,266)	24,775
Capital and investment expenditures	808	741	12	(9)	1,552

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income and other income and expense items as discussed below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities. 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)	**2008**	2007	2006
OTHER INCOME			
Nonregulated energy and delivery services income	**$38**	$36	$41
DIG Issue C20 amortization (Note 17A)	**3**	4	5
Gain on sale of Level 3 Communications, Inc. stock [(a)]	–	–	32
Investment gains, net	–	5	4
Income from equity investments, net	**1**	–	–
Reversal of indemnification liability (Note 21B)	–	–	29
Other, net	**3**	–	–
Total other income	**45**	45	111
OTHER EXPENSE			
Nonregulated energy and delivery services expenses	**21**	24	27
Donations	**25**	22	20
Contingent value obligation unrealized loss, net (Note 15)	–	2	25
Investment losses, net	**13**	–	–
Loss from equity investments, net	–	3	2
Loss on debt redemption[(b)]	–	–	59
Derivative mark-to-market losses, net	**3**	–	–
Indemnification liability (Note 21B)	–		13
Other, net	–	1	2
Total other expense	**62**	52	148
Other, net – Progress Energy	**$(17)**	$(7)	$(37)

PEC

(in millions)	2008	2007	2006
OTHER INCOME			
Nonregulated energy and delivery services income	**$20**	$14	$15
DIG Issue C20 amortization (Note 17A)	**3**	4	5
Investment gains, net	**–**	1	–
Reversal of indemnification liability (Note 21B)	**–**	–	29
Other, net	**8**	4	3
Total other income	**31**	23	52
OTHER EXPENSE			
Nonregulated energy and delivery services expenses	**9**	8	7
Donations	**14**	9	10
Losses from equity investments, net	**1**	–	1
Derivative mark-to-market losses	**3**	–	–
Indemnification liability (Note 21B)	**–**	–	13
Total other expense	**27**	17	31
Other, net – PEC	**$4**	$6	$21

PEF

(in millions)	2008	2007	2006
OTHER INCOME			
Nonregulated energy and delivery services income	**$20**	$24	$26
Investment gains, net	**–**	2	2
Other, net	**2**	–	–
Total other income	**22**	26	28
OTHER EXPENSE			
Nonregulated energy and delivery services expenses	**12**	16	20
Donations	**11**	8	10
Investment losses, net	**9**	–	–
Losses from equity investments, net	**–**	1	1
Other, net	**–**	3	1
Total other expense	**32**	28	32
Other, net – PEF	**$(10)**	$(2)	$(4)

(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 Communications, Inc. stock received as part of the sale of our interest in PT LLC (See Note 3F). These gains are prior to the consideration of minority interest.

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

21. ENVIRONMENTAL MATTERS

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

A. HAZARDOUS AND SOLID WASTE

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

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

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

(in millions)	**2008**	2007
PEC		
MGP and other sites[a]	**$16**	$16
PEF		
Remediation of distribution and substation transformers	**22**	31
MGP and other sites	**15**	17
Total PEF environmental remediation accruals[b]	**37**	48
Total Progress Energy environmental remediation accruals	**$53**	$64

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

PROGRESS ENERGY

In addition to the Utilities' sites, discussed under "PEC" and "PEF" below, we incurred indemnity obligations related to certain pre-closing liabilities of divested subsidiaries, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC

In 2006, the NCUC and the SCPSC authorized PEC to defer and amortize certain environmental remediation expenses. Remediation expenses not authorized to be deferred are included in operation and maintenance expense.

Including the Ward Transformer site located in Raleigh, N.C. (Ward), and MGP sites discussed below, for the year ended December 31, 2008, PEC accrued approximately $8 million, of which $2 million was deferred, and spent approximately $8 million. These amounts primarily relate to the Ward site. For the year ended December 31, 2007, including the Carolina Transformer site, the Ward site and MGP sites discussed below, PEC's accrual was reduced by a net amount of approximately $2 million and PEC spent approximately $4 million. For the year ended December 31, 2006, PEC accrued approximately $21 million and spent approximately $6 million. The 2006 accrual included $12 million for the minimum estimated total remediation cost for all of PEC's remaining MGP sites 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.

PEC has recorded a minimum estimated total remediation cost for all of its remaining MGP sites based upon its historical experience with remediation of several of its MGP sites. The maximum amount of the range for all the sites cannot be determined at this time as one of the remaining sites is significantly larger than the sites for which we have historical experience. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

During the fourth quarter of 2004, the EPA advised PEC that it had been identified as a PRP at the Ward site. The EPA offered PEC and a number of other PRPs the opportunity to negotiate the removal action for the Ward site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the Ward site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the Ward site. During 2007, the PRP agreement was amended to include an additional participating PRP, which reduced, on an interim basis, PEC's proportionate responsibility for funding the remediation. During 2008, PEC increased its accrual due to an increase in the estimated scope of work. At December 31, 2008 and 2007, PEC's recorded liability for the site was approximately $7 million and $6 million, respectively. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. On September 12, 2008, PEC filed a complaint seeking contribution for and recovery of costs incurred in remediating the Ward site, as well as a declaratory judgment that defendants are jointly and severally liable for response costs at the site. The complaint names 28 parties that did not sign a tolling agreement with PEC, which was entered into by over 200 PRPs. The tolling agreement suspends the running of the statute of limitations for determination of cost recovery from PRPs at the Ward site. The litigation has been stayed to allow the parties to explore private settlements. The outcome of these matters cannot be predicted.

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

PEF

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF has reviewed all distribution transformer sites and all substation sites for mineral oil-impacted soil caused by equipment integrity issues. Should further distribution transformer sites be identified outside of this population, the distribution operations and maintenance expense (O&M) costs will not be recoverable through the ECRC. Based on historical experience, PEF projects costs will be between approximately $3 million and $4 million per year. For the year ended December 31, 2008, PEF accrued approximately $17 million, due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $26 million related to the remediation of transformers. For the year ended December 31, 2007, PEF accrued approximately $10 million due to an increase in estimated remediation costs and spent approximately $22 million related to the remediation of transformers. For the year ended December 31, 2006, PEF accrued approximately $42 million due to additional sites expected to require remediation and spent approximately $19 million related to the remediation of transformers. At December 31, 2008 and 2007, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

The amounts for MGP and other sites, in the previous table, 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, 2008, PEF made no accruals and spent approximately $2 million. For the year ended December 31, 2007, PEF made no accruals and spent approximately $1 million. For the year ended December 31, 2006, PEF made no accruals and PEF's expenditures were not material to our or PEF's results of operations or financial condition.

B. AIR AND WATER QUALITY

At December 31, 2008 and 2007, we were subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations included the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the Clean Smokestacks Act and mercury regulation. PEC's and PEF's environmental compliance capital expenditures related to these regulations began in 2002 and 2005, respectively. At December 31, 2008, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.859 billion, including $1.012 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and $847 million at PEF, which related entirely to in-process CAIR projects. At December 31, 2007, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.225 billion, including $902 million at PEC and $323 million at PEF. PEC completed installation of controls to meet the requirements of the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) in 2007.

PEF participated in a coalition of Florida utilities that filed a challenge to the CAIR as it applied to Florida. PEF withdrew from the coalition during the fourth quarter of 2008. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, including the Florida challenge, which vacated the CAIR in its entirety. On September 24, 2008, petitions for rehearing were filed by a number of parties. On December 23, 2008, the D.C. Court of Appeals remanded the case without vacating the CAIR for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. The outcome of the EPA's further proceedings cannot be predicted. The Court's December 23, 2008 decision remanding the CAIR maintained its current implementation such that CAIR satisfies best available retrofit technology (BART) for SO_2 and NOx for BART-affected units under the CAVR. Depending on whether this determination continues to be maintained as the CAIR is revised, for BART-eligible units CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions. As a result, BART for SO_2 and NOx could apply to PEC's and PEF's BART-eligible units.

On February 8, 2008, the D.C. Court of Appeals vacated the delisting determination and the Clean Air Mercury Rule (CAMR). On September 17, 2008, the Utility Air Regulatory Group filed a petition for writ of certiorari with the U.S. Supreme Court seeking a review of the decision that vacated the CAMR. On October 17, 2008, the EPA filed a similar petition and subsequently withdrew it on

January 29, 2009. The Utility Air Regulatory Group's petition for writ of certiorari was denied on February 23, 2009. The three states in which the Utilities operate adopted mercury regulations implementing CAMR and submitted their state implementation rules to the EPA. It is uncertain how the decision that vacated the federal CAMR and any review granted by the Supreme Court will affect the state rules; however, state-specific provisions are likely to remain in effect. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. We are currently evaluating the impact of these decisions. The outcome of these matters cannot be predicted.

PEF is continuing construction of its in-process emission control projects. On December 18, 2008, PEF and the FDEP announced an agreement under which PEF will retire Crystal River Units No. 1 and No. 2 (CR1 and CR2) as coal-fired units and complete construction of its emission control projects at CR 4 and CR 5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which is anticipated to be around 2020.

We account for emission allowances as inventory using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. At December 31, 2008, PEC had approximately $22 million in SO_2 emission allowances, which will be utilized to comply with existing Clean Air Act requirements, and an immaterial amount of NOx emission allowances. In order to achieve compliance with the requirements of the CAIR pursuant to its Integrated Clean Air Compliance Plan, PEF needed to purchase CAIR seasonal and annual NOx allowances. On November 12, 2008, the FPSC approved PEF's petition for recovery of its CAIR expenses, including NOx allowance inventory expense, through the ECRC. At December 31, 2008, PEF had approximately $59 million in annual NOx emission allowance inventory, $6 million in seasonal NOx emission allowance inventory and approximately $11 million in SO_2 emission allowance inventory. SO_2 emission allowances will be utilized to comply with existing Clean Air Act requirements.

As discussed in Note 7B, in June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. Two of PEC's largest coal-fired generating units (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. Pursuant to joint ownership agreements, the joint owners are required to pay a portion of the costs of owning and operating these plants. PEC has determined that the most cost-effective Clean Smokestacks Act compliance strategy is to maximize the SO_2 removal from its larger coal-fired units, including Roxboro No. 4 and Mayo, so as to avoid the installation of expensive emission controls on its smaller coal-fired units. In order to address the joint owner's concerns that such a compliance strategy would result in a disproportionate share of the cost of compliance for the jointly owned units, in 2005 PEC entered into an agreement with the joint owner to limit its aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately $38 million. PEC recorded a related liability for the joint owner's share of estimated costs in excess of the contract amount. At December 31, 2008 and 2007, the amount of the liability was $10 million and $30 million, respectively, based upon the respective estimates for the remaining Clean Smokestacks Act compliance costs. During the year ended December 31, 2008, PEC made no additional accruals and spent approximately $20 million that exceeded the joint owner limit. Because PEC has taken a system-wide compliance approach, its North Carolina retail ratepayers have significantly benefited from the strategy of focusing emission reduction efforts on the jointly owned units, and, therefore, PEC believes that any costs in excess of the joint owner's share should be recovered from North Carolina retail ratepayers, consistent with other capital expenditures associated with PEC's compliance with the Clean Smokestacks Act. On November 2, 2006, PEC notified the NCUC of its intent to record these estimated excess costs as part the Clean Smokestacks amortization, and subsequently reclassified $29 million of indemnification expense to Clean Smokestacks amortization. On September 5, 2008, the NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million, including eligible compliance costs in excess of the joint owner's share, as the projects are closed to plant in service (See Note 7B).

22. COMMITMENTS AND CONTINGENCIES

A. PURCHASE OBLIGATIONS

In most cases, our purchase obligation contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. At December 31, 2008, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2009	2010	2011	2012	2013	Thereafter
Fuel	$3,186	$2,532	$1,938	$1,532	$1,167	$6,669
Purchased power	422	432	447	436	419	3,477
Construction obligations	1,098	1,458	1,532	1,433	1,511	2,418
Other purchase obligations	53	68	40	33	24	168
Total	$4,759	$4,490	$3,957	$3,434	$3,121	$12,732

PEC

(in millions)	2009	2010	2011	2012	2013	Thereafter
Fuel	$1,619	$1,272	$832	$596	$561	$1,593
Purchased power	87	92	99	85	78	598
Construction obligations	182	72	16	–	2	–
Other purchase obligations	7	3	3	3	3	6
Total	$1,895	$1,439	$950	$684	$644	$2,197

PEF

(in millions)	2009	2010	2011	2012	2013	Thereafter
Fuel	$1,567	$1,260	$1,106	$936	$606	$5,076
Purchased power	335	340	348	351	341	2,879
Construction obligations	916	1,386	1,516	1,433	1,509	2,418
Other purchase obligations	36	30	36	29	21	162
Total	$2,854	$3,016	$3,006	$2,749	$2,477	$10,535

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 $3.078 billion, $2.360 billion and $1.628 billion for 2008, 2007 and 2006, respectively. PEC's total payments under these commitments for its generating plants were $1.446 billion, $1.049 billion and $1.051 billion in 2008, 2007 and 2006, respectively. PEF's payments totaled $1.632 billion, $1.311 billion and $577 million in 2008, 2007 and 2006, respectively.

In December 2008, PEF entered into a nuclear fuel fabrication contract for the planned Levy nuclear units. (See discussion under Construction Obligations below.) This $355 million contract (fuel plus related core components) is for the period from 2014 through 2027 and contains exit provisions with termination fees that vary based on the circumstance.

Both PEC and PEF have ongoing purchased power contracts with certain co-generators (primarily QFs) with expiration dates ranging from 2009 to 2028. These purchased power contracts generally provide for capacity and energy payments.

PEC has a long-term agreement for the purchase of power and related transmission services from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The agreement provides for the purchase of 250 MW (19 percent of net output) of capacity through

2009 with an estimated remaining 2009 payment of approximately $29 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $90 million, $77 million and $80 million for 2008, 2007 and 2006, respectively.

PEC executed two long-term tolling agreements for the purchase of all of the power generated from Broad River LLC's Broad River facility (Broad River). One agreement provides for the purchase of approximately 500 MW of capacity through May 2021 with average minimum annual payments of approximately $25 million, primarily representing capital-related capacity costs. The second agreement provides for the additional purchase of approximately 335 MW of capacity through February 2022 with average annual payments of approximately $26 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River agreements amounted to $44 million, $39 million and $45 million in 2008, 2007 and 2006, respectively.

In 2007, PEC executed long-term agreements for the purchase of power from Southern Power Company. The agreements provide for capacity purchases of 305 MW (68 percent of net output) for 2010, 310 MW (30 percent of net output) for 2011 and 150 MW (33 percent of net output) annually thereafter through 2019. Estimated payments for capacity under the agreements are $23 million for 2010, $24 million for 2011 and $16 million annually thereafter through 2019.

PEC has various pay-for-performance contracts with QFs, including renewable energy, for approximately 200 MW of firm capacity expiring at various times through 2028. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $55 million, $95 million and $182 million in 2008, 2007 and 2006, respectively.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with Southern Company for approximately 414 MW (19 percent of net output) of purchased power annually through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $178 million, $161 million and $162 million for 2008, 2007 and 2006, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $70 million, $65 million, $56 million, $48 million and $42 million for 2009 through 2013, respectively, and $102 million payable thereafter.

PEF has ongoing purchased power contracts with certain QFs for 786 MW of firm capacity with expiration dates ranging from 2009 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. All ongoing commitments have been approved by the FPSC. Total capacity purchases under these contracts amounted to $273 million, $288 million and $277 million for 2008, 2007 and 2006, respectively. At December 31, 2008, minimum expected future capacity payments under these contracts were $263 million, $267 million, $281 million, $292 million and $288 million for 2009 through 2013, respectively, and $2.751 billion payable thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

In June 2008, PEC entered into a conditional contract with an interstate pipeline for firm pipeline transportation capacity to support PEC's gas supply needs for the period from May 2011 through April 2031. The estimated total cost to PEC associated with this agreement is approximately $487 million. The transaction is subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of this agreement, the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In July 2008, PEC entered into an amendment to an existing transportation service agreement with an intrastate pipeline for firm pipeline transportation capacity to support PEC's gas supply needs for the period from April 2011 through May 2030. The total additional cost to PEC associated with this amendment is estimated to be approximately $54 million. The amendment is subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related intrastate natural gas pipeline system expansions and other contractual provisions. 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 April 2008 (and as amended in February 2009), PEF entered into conditional contracts and extensions of existing contracts with Florida Gas Transmission Company, LLC (FGT) for firm pipeline transportation capacity to support PEF's gas supply needs for the period from April 2011 through March 2036. The total cost to PEF associated with these agreements is estimated to be approximately $1.086 billion. The contracts are subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions and other contractual provisions. In addition to the FGT contracts, during 2008, PEF entered into additional gas supply and transportation arrangements for the period from 2010 through 2025 that are subject to certain conditions. The total current notional cost of these additional agreements is estimated to be approximately $849 million. Due to the conditions of these agreements, the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $1.018 billion, $698 million and $387 million for 2008, 2007 and 2006, respectively.

PEC has purchase obligations related to various capital projects including new generation, transmission and obligations related to the Clean Smokestacks Act. Total payments under PEC's construction-related contracts were $140 million, $208 million and $233 million for 2008, 2007 and 2006, respectively. PEC's future obligations under these contracts are $182 million, $72 million, $16 million and $1 million for 2009, 2010, 2011 and 2013, respectively. PEC has no future obligation under these contracts for 2012.

The majority of PEF's construction obligations relate to an engineering, procurement and construction (EPC) agreement that PEF entered into in December 2008 with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two approximately 1,100-MW Westinghouse AP1000 nuclear units planned for construction at Levy. Estimated payments and associated escalation totaling $8.736 billion are included for the multi-year contract and do not assume any joint ownership. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstance. See Note 7C for additional information about the Levy project. In 2008, PEF made payments of $117 million toward long-lead equipment and engineering related to the EPC agreement. Additionally, PEF has other construction obligations related to various capital projects including new generation, transmission and environmental compliance. Total payments under PEF's other construction-related contracts were $761 million, $490 million and $154 million for 2008, 2007 and 2006, respectively.

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and PEF service agreements related to the Hines Energy Complex and the Bartow plant. Our payments under these agreements were $110 million, $75 million and $100 million for 2008, 2007 and 2006, respectively.

PEC has various purchase obligations for emission obligations, limestone supply and fleet vehicles. Total purchases under these contracts were $36 million, $25 million and $51 million for 2008, 2007 and 2006, respectively. Future obligations under these contracts are $7 million for 2009, $3 million each for 2010 through 2013 and $6 million thereafter.

Among PEF's other purchase obligations, PEF has long-term service agreements for the Hines Energy Complex and the Bartow plant, emission obligations and fleet vehicles. Total payments under these contracts were $58 million, $24 million and $19 million for 2008, 2007 and 2006, respectively. Future obligations are primarily comprised of the long-term service agreements. These agreements total $31 million, $29 million, $36 million, $29 million and $21 million for 2009 through 2013, respectively, with approximately $162 million payable thereafter.

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 $38 million, $40 million and $42 million for 2008, 2007 and 2006, respectively. Our purchased power expense under agreements classified as operating leases was approximately $152 million, $69 million and $60 million in 2008, 2007 and 2006, respectively.

PEC's rent expense under operating leases totaled $26 million, $23 million and $25 million during 2008, 2007 and 2006, respectively. These amounts include rent expense allocated from PESC to PEC of $5 million, $6 million and $8 million for 2008, 2007 and 2006, respectively. Purchased power expense under agreements classified as operating leases was approximately $9 million, $10 million and $10 million in 2008, 2007 and 2006, respectively.

PEF's rent expense under operating leases totaled $11 million, $15 million and $16 million during 2008, 2007 and 2006, respectively. These amounts include rent expense allocated from PESC to PEF of $3 million, $6 million and $7 million for 2008, 2007 and 2006, respectively. Purchased power expense under agreements classified as operating leases was approximately $142 million, $59 million and $49 million in 2008, 2007 and 2006, respectively.

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

	Progress Energy		PEC		PEF	
(in millions)	**2008**	2007	**2008**	2007	**2008**	2007
Buildings	**$267**	$267	**$30**	$30	**$237**	$237
Less: Accumulated amortization	**(28)**	(20)	**(14)**	(13)	**(14)**	(7)
Total	**$239**	$247	**$16**	$17	**$223**	$230

At December 31, 2008, 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
2009	$29	$48	$3	$37	$26	$7
2010	28	29	2	21	26	5
2011	28	23	2	16	26	4
2012	28	38	2	13	26	22
2013	36	64	10	31	26	31
Thereafter	272	955	–	559	272	394
Minimum annual payments	421	$1,157	19	$677	402	$463
Less amount representing imputed interest	(182)		(3)		(179)	
Present value of net minimum lease payments under capital leases	$239		$16		$223	

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

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

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

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

In 2006, PEF extended the terms of a 517-MW (100 percent of net output) tolling agreement for purchased power, which is classified as a capital lease of the related plant, for an additional 10 years. The agreement calls for minimum annual payments of approximately $21 million from April 2007 through April 2024, for a total of approximately $348 million. Due to the conditions of the agreement, the capital lease was not recorded on our or PEF's Balance Sheets until 2007.

In 2006, PEF entered into an agreement for 116.6-MW (100 percent of net output) purchased power, which is classified as a capital lease of the related plant. Due to the conditions of the agreement, the capital lease will not be recorded on PEF's Balance Sheet until approximately 2011. Therefore, this capital lease is not included in the table above. The agreement calls for minimum annual payments of approximately $7 million from 2012 through November 2036, for a total of approximately $170 million.

Excluding the Utilities, we are also a lessor of land, buildings and other types of properties we own under operating leases with various terms and expiration dates. The leased buildings are depreciated under the same terms as other buildings included in diversified business property. Minimum rentals receivable under noncancelable leases are approximately $8 million, $6 million, $5 million, $2 million and $1 million for 2009 through 2013, respectively. Rents received under these operating leases totaled $9 million, $8 million and $9 million for 2008, 2007 and 2006, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $10 million for 2009 and none thereafter. PEC's rents received are contingent upon usage and totaled $33 million each for 2008 and 2007 and $31 million for 2006. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $81 million, $78 million and $72 million for 2008, 2007 and 2006, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2009 and thereafter.

C. GUARANTEES

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties, which are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2008, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Consolidated Balance Sheets.

At December 31, 2008, we have issued guarantees and indemnifications of and for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, which are within the scope of FIN 45. Related to the sales of businesses, the latest specified notice period extends until 2013 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. 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, 2008, the estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $458 million, including $32 million at PEF. At December 31, 2008 and 2007, we had recorded liabilities related to guarantees and indemnifications to third parties of approximately $61 million and $80 million, respectively. These amounts included $10 million and $30 million, respectively, for PEC and $8 million for PEF at December 31, 2008 and 2007. During the year ended December 31, 2008, PEC made no additional accruals and spent approximately $20 million that exceeded the joint owner limit. As current estimates change, it is possible that additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

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

D. OTHER COMMITMENTS AND CONTINGENCIES

SPENT NUCLEAR FUEL MATTERS

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

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

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

SYNTHETIC FUELS MATTERS

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); Earthco; certain affiliates of Earthco; EFC Synfuel LLC (which was owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to Purchase Agreement as of August 23, 2000 (the Asset Purchase Agreement). Global has asserted (1) that pursuant to the Asset Purchase Agreement, it is entitled to an interest in two synthetic fuels facilities previously owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it is entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities and (3) a number of tort claims are related to the contracts.

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

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

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

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

In January 2008, Global agreed to simplify the Florida action by dismissing the tort claims. The Florida Global Case continues now under contract theories alone. The case is scheduled to go to trial in June 2009. We cannot predict the outcome of this matter.

OTHER LITIGATION MATTERS

We and our subsidiaries are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, we have made accruals and disclosures in accordance with SFAS No. 5, "Accounting for Contingencies," to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

23. CONDENSED CONSOLIDATING STATEMENTS

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

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

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

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. As of December 31, 2008, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 11B, there were no restrictions on PEC's or PEF's retained earnings.

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

Condensed Consolidating Statement of Income
Year Ended December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Operating revenues	$–	$4,738	$4,429	$–	$9,167
Operating expenses					
Fuel used in electric generation	–	1,675	1,346	–	3,021
Purchased power	–	953	346	–	1,299
Operation and maintenance	3	813	1,030	(26)	1,820
Depreciation, amortization and accretion	–	306	518	15	839
Taxes other than on income	–	309	198	1	508
Other	–	1	(5)	1	(3)
Total operating expenses	3	4,057	3,433	(9)	7,484
Operating (loss) income	(3)	681	996	9	1,683
Other income (expense)					
Interest income	11	9	12	(8)	24
Allowance for equity funds used during construction	–	95	27	–	122
Other, net	–	(18)	4	(3)	(17)
Total other income (expense), net	11	86	43	(11)	129
Interest charges					
Interest charges	201	263	219	(4)	679
Allowance for borrowed funds used during construction	–	(28)	(12)	–	(40)
Total interest charges, net	201	235	207	(4)	639
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(193)	532	832	2	1,173
Income tax (benefit) expense	(85)	172	298	10	395
Equity in earnings of consolidated subsidiaries	941	–	–	(941)	–
Minority interest in subsidiaries' income, net of tax	–	(5)	–	–	(5)
Income (loss) from continuing operations	833	355	534	(949)	773
Discontinued operations, net of tax	(3)	60	–	–	57
Net income (loss)	$830	$415	$534	$(949)	$830

Condensed Consolidating Statement of Income
Year Ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Operating revenues	$–	$4,768	$4,385	$–	$9,153
Operating expenses					
Fuel used in electric generation	–	1,764	1,381	–	3,145
Purchased power	–	882	302	–	1,184
Operation and maintenance	10	834	1,024	(26)	1,842
Depreciation, amortization and accretion	–	369	519	17	905
Taxes other than on income	–	309	192	–	501
Other	–	20	(2)	12	30
Total operating expenses	10	4,178	3,416	3	7,607
Operating (loss) income	(10)	590	969	(3)	1,546
Other income (expense)					
Interest income	27	8	21	(22)	34
Allowance for equity funds used during construction	–	41	10	–	51
Other, net	–	(2)	6	(11)	(7)
Total other income (expense), net	27	47	37	(33)	78
Interest charges					
Interest charges	203	210	215	(23)	605
Allowance for borrowed funds used during construction	–	(12)	(5)	–	(17)
Total interest charges, net	203	198	210	(23)	588
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(186)	439	796	(13)	1,036
Income tax (benefit) expense	(79)	117	295	1	334
Equity in earnings of consolidated subsidiaries	596	–	–	(596)	–
Minority interest in subsidiaries' income, net of tax	–	(9)	–	–	(9)
Income (loss) from continuing operations	489	313	501	(610)	693
Discontinued operations, net of tax	15	30	–	(234)	(189)
Net income (loss)	$504	$343	$501	$(844)	$504

Condensed Consolidating Statement of Income
Year Ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Operating revenues	$–	$4,637	$4,086	$1	$8,724
Operating expenses					
Fuel used in electric generation	–	1,835	1,173	–	3,008
Purchased power	–	766	334	–	1,100
Operation and maintenance	14	684	930	(45)	1,583
Depreciation, amortization and accretion	–	406	571	34	1,011
Taxes other than on income	–	309	191	–	500
Other	–	21	–	14	35
Total operating expenses	14	4,021	3,199	3	7,237
Operating (loss) income	(14)	616	887	(2)	1,487
Other income (expense)					
Interest income	47	15	25	(28)	59
Allowance for equity funds used during construction	–	17	4	–	21
Other, net	(80)	23	21	(1)	(37)
Total other (expense) income, net	(33)	55	50	(29)	43
Interest charges					
Interest charges	276	187	217	(49)	631
Allowance for borrowed funds used during construction	–	(5)	(2)	–	(7)
Total interest charges, net	276	182	215	(49)	624
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	489	722	18	906
Income tax (benefit) expense	(123)	174	265	23	339
Equity in earnings of consolidated subsidiaries	779	–	–	(779)	–
Minority interest in subsidiaries' income, net of tax	–	(16)	–	–	(16)
Income (loss) from continuing operations	579	299	457	(784)	551
Discontinued operations, net of tax	(8)	400	–	(372)	20
Net income (loss)	$571	$699	$457	$(1,156)	$571

Condensed Consolidating Balance Sheet
December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Enery, Inc.
ASSETS					
Utility plant, net	$–	$8,790	$9,385	$118	$18,293
Current assets					
Cash and cash equivalents	88	73	18	1	180
Receivables, net	–	363	502	2	867
Notes receivable from affiliated companies	34	44	55	(133)	–
Inventory	–	606	633	–	1,239
Regulatory assets	–	326	207	–	533
Derivative collateral posted	–	335	18	–	353
Prepayments and other current assets	48	169	137	(6)	348
Total current assets	170	1,916	1,570	(136)	3,520
Deferred debits and other assets					
Investment in consolidated subsidiaries	11,924	–	–	(11,924)	–
Regulatory assets	–	1,324	1,243	–	2,567
Nuclear decommissioning trust funds	–	417	672	–	1,089
Goodwill	–	–	–	3,655	3,655
Other assets and deferred debits	155	196	295	103	749
Total deferred debits and other assets	12,079	1,937	2,210	(8,166)	8,060
Total assets	$12,249	$12,643	$13,165	$(8,184)	$29,873
CAPITALIZATION AND LIABILITIES					
Capitalization					
Common stock equity	$8,687	$3,519	$4,301	$(7,820)	$8,687
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	–	93
Minority interest	–	3	–	3	6
Long-term debt, affiliate	–	309	–	(37)	272
Long-term debt, net	2,696	4,182	3,509	–	10,387
Total capitalization	11,383	8,047	7,869	(7,854)	19,445
Current liabilities					
Short-term debt	569	371	110	–	1,050
Notes payable to affiliated companies	–	206	–	(206)	–
Derivative liabilities	31	380	82	–	493
Other current liabilities	220	964	773	(14)	1,943
Total current liabilities	820	1,921	965	(220)	3,486
Deferred credits and other liabilities					
Noncurrent income tax liabilities	1	118	1,111	(412)	818
Regulatory liabilities	–	1,076	987	118	2,181
Accrued pension and other benefits	10	540	856	188	1,594
Other liabilities and deferred credits	35	941	1,377	(4)	2,349
Total deferred credits and other liabilities	46	2,675	4,331	(110)	6,942
Total capitalization and liabilities	$12,249	$12,643	$13,165	$(8,184)	$29,873

Condensed Consolidating Balance Sheet
December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$–	$7,600	$8,880	$125	$16,605
Current assets					
Cash and cash equivalents	185	43	25	2	255
Receivables, net	–	574	446	102	1,122
Notes receivable from affiliated companies	157	149	–	(306)	–
Inventory	–	484	510	–	994
Regulatory assets	–	6	148	–	154
Assets to be divested	–	48	–	4	52
Prepayments and other current assets	21	188	110	(94)	225
Total current assets	363	1,492	1,239	(292)	2,802
Deferred debits and other assets					
Investment in consolidated subsidiaries	10,942	–	–	(10,942)	–
Regulatory assets	–	266	680	–	946
Nuclear decommissioning trust funds	–	580	804	–	1,384
Goodwill	–	1	–	3,654	3,655
Other assets and deferred debits	149	729	352	(284)	946
Total deferred debits and other assets	11,091	1,576	1,836	(7,572)	6,931
Total assets	$11,454	$10,668	$11,955	$(7,739)	$26,338
CAPITALIZATION AND LIABILITIES					
Common stock equity	$8,395	$3,052	$3,752	$(6,804)	$8,395
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	–	93
Minority interest	–	81	–	3	84
Long-term debt, affiliate	–	309	–	(38)	271
Long-term debt, net	2,597	2,686	3,183	–	8,466
Total capitalization	10,992	6,162	6,994	(6,839)	17,309
Current liabilities					
Current portion of long-term debt	–	577	300	–	877
Short-term debt	201	–	–	–	201
Notes payable to affiliated companies	–	227	154	(381)	–
Derivative liabilities	–	38	19	–	57
Liabilities to be divested	–	8	–	–	8
Other current liabilities	215	1,199	697	48	2,159
Total current liabilities	416	2,049	1,170	(333)	3,302
Deferred credits and other liabilities					
Noncurrent income tax liabilities	–	59	936	(634)	361
Regulatory liabilities	–	1,330	1,098	126	2,554
Accrued pension and other benefits	12	347	459	(55)	763
Other liabilities and deferred credits	34	721	1,298	(4)	2,049
Total deferred credits and other liabilities	46	2,457	3,791	(567)	5,727
Total capitalization and liabilities	$11,454	$10,668	$11,955	$(7,739)	$26,338

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Net cash (used) provided by operating activities	$(90)	$221	$1,061	$26	$1,218
Investing activities					
Gross property additions	–	(1,553)	(760)	(20)	(2,333)
Nuclear fuel additions	–	(43)	(179)	–	(222)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	59	8	5	72
Proceeds from sales of assets to affiliated companies	–	12	–	(12)	–
Purchases of available-for-sale securities and other investments	(7)	(783)	(682)	(118)	(1,590)
Proceeds from available-for-sale securities and other investments	–	788	626	120	1,534
Changes in advances to affiliated companies	123	105	(55)	(173)	–
Contributions to consolidated subsidiaries	(101)	–	–	101	–
Other investing activities	20	8	–	(30)	(2)
Net cash provided (used) by investing activities	35	(1,407)	(1,042)	(127)	(2,541)
Financing activities					
Issuance of common stock	132	–	–	–	132
Dividends paid on common stock	(642)	–	–	–	(642)
Dividends paid to parent	–	(33)	–	33	–
Payments of short-term debt with original maturities greater than 90 days	(176)	–	–	–	(176)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	29	–	–	–	29
Net increase in short-term debt	615	371	110	–	1,096
Proceeds from issuance of long-term debt, net	–	1,475	322	–	1,797
Retirement of long-term debt	–	(577)	(300)	–	(877)
Cash distributions to minority interests of consolidated subsidiaries	–	(85)	–	–	(85)
Changes in advances from affiliated companies	–	(21)	(154)	175	–
Contributions from parent	–	85	15	(100)	–
Other financing activities	–	1	(19)	(8)	(26)
Net cash (used) provided by financing activities	(42)	1,216	(26)	100	1,248
Net (decrease) increase in cash and cash equivalents	(97)	30	(7)	(1)	(75)
Cash and cash equivalents at beginning of year	185	43	25	2	255
Cash and cash equivalents at end of year	$88	$73	$18	$1	$180

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

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$76	$489	$1,018	$(331)	$1,252
Investing activities					
Gross property additions	–	(1,218)	(757)	2	(1,973)
Nuclear fuel additions	–	(44)	(184)	–	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	51	10	614	675
Purchases of available-for-sale securities and other investments	–	(640)	(603)	(170)	(1,413)
Proceeds from available-for-sale securities and other investments	21	640	622	169	1,452
Changes in advances to affiliated companies	(99)	(112)	24	187	–
Return of investment in consolidated subsidiaries	340	–	–	(340)	–
Other investing activities	(31)	32	(4)	33	30
Net cash provided (used) by investing activities	231	(1,291)	(892)	495	(1,457)
Financing activities					
Issuance of common stock	151	–	–	–	151
Dividends paid on common stock	(627)	–	–	–	(627)
Dividends paid to parent	–	(10)	(143)	153	–
Proceeds from issuance of short-term debt with original maturities greater than 90 days	176	–	–	–	176
Net increase in short-term debt	25	–	–	–	25
Proceeds from issuance of long-term debt, net	–	739	–	–	739
Retirement of long-term debt	–	(124)	(200)	–	(324)
Cash distributions to minority interests of consolidated subsidiaries	–	(10)	–	–	(10)
Changes in advances from affiliated companies	–	151	154	(305)	–
Contributions from parent	–	10	21	(31)	–
Other financing activities	–	49	(4)	20	65
Net cash (used) provided by financing activities	(275)	805	(172)	(163)	195
Net increase (decrease) in cash and cash equivalents	32	3	(46)	1	(10)
Cash and cash equivalents at beginning of year	153	40	71	1	265
Cash and cash equivalents at end of year	$185	$43	$25	$2	$255

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

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$1,295	$1,110	$1,094	$(1,498)	$2,001
Investing activities					
Gross property additions	–	(865)	(705)	(2)	(1,572)
Nuclear fuel additions	–	(12)	(102)	–	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	1,242	5	410	1,657
Purchases of available-for-sale securities and other investments	(919)	(625)	(896)	(12)	(2,452)
Proceeds from available-for-sale securities and other investments	898	724	1,006	3	2,631
Changes in advances to affiliated companies	409	(39)	(24)	(346)	–
Proceeds from repayment of long-term affiliate debt	131	–	–	(131)	–
Return of investment in consolidated subsidiaries	287	–	–	(287)	–
Other investing activities	(63)	(6)	(6)	52	(23)
Net cash provided (used) by investing activities	743	419	(722)	(313)	127
Financing activities					
Issuance of common stock	185	–	–	–	185
Dividends paid on common stock	(607)	–	–	–	(607)
Dividends paid to parent	–	(1,135)	(339)	1,474	–
Net decrease in short-term debt	–	(102)	(73)	–	(175)
Proceeds from issuance of long-term debt, net	397	–	–	–	397
Retirement of long-term debt	(2,091)	(109)	–	–	(2,200)
Retirement of long-term affiliate debt	–	(131)	–	131	–
Cash distributions to minority interests of consolidated subsidiaries	–	(79)	–	–	(79)
Changes in advances from affiliated companies	–	(243)	(11)	254	–
Contributions from parent	–	67	–	(67)	–
Other financing activities	(8)	4	(3)	18	11
Net cash (used) provided by financing activities	(2,124)	(1,728)	(426)	1,810	(2,468)
Net decrease in cash and cash equivalents	(86)	(199)	(54)	(1)	(340)
Cash and cash equivalents at beginning of year	239	239	125	2	605
Cash and cash equivalents at end of year	$153	$40	$71	$1	$265

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data was as follows:

Progress Energy

(in millions except per share data)	First	Second	Third	Fourth
2008				
Operating revenues	**$2,066**	**$2,244**	**$2,696**	**$2,161**
Operating income	**365**	**406**	**591**	**321**
Income from continuing operations	**149**	**200**	**308**	**116**
Net income	**209**	**205**	**309**	**107**
Common stock data				
Basic earnings per common share				
Income from continuing operations	**0.58**	**0.77**	**1.18**	**0.44**
Net income	**0.81**	**0.79**	**1.19**	**0.41**
Diluted earnings per common share				
Income from continuing operations	**0.58**	**0.77**	**1.18**	**0.44**
Net income	**0.81**	**0.79**	**1.18**	**0.41**
Dividends declared per common share	**0.615**	**0.615**	**0.615**	**0.620**
Market price per share – High	**49.16**	**43.58**	**45.52**	**45.60**
– Low	**40.54**	**41.00**	**40.11**	**32.60**
2007				
Operating revenues	$2,072	$2,129	$2,750	$2,202
Operating income	351	301	610	284
Income from continuing operations	149	138	311	95
Net income (loss)	275	(193)	319	103
Common stock data				
Basic earnings per common share				
Income from continuing operations	0.59	0.54	1.21	0.37
Net income (loss)	1.08	(0.75)	1.24	0.40
Diluted earnings per common share				
Income from continuing operations	0.59	0.54	1.21	0.37
Net income (loss)	1.08	(0.75)	1.24	0.40
Dividends declared per common share	0.610	0.610	0.610	0.615
Market price per share – High	51.60	52.75	49.48	50.25
– Low	47.05	45.15	43.12	44.75

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.

PEC

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2008				
Operating revenues	**$1,068**	**$1,048**	**$1,266**	**$1,047**
Operating income	**240**	**205**	**353**	**198**
Net income	**123**	**104**	**201**	**106**
2007				
Operating revenues	$1,058	$996	$1,286	$1,045
Operating income	235	180	375	179
Net income	124	88	204	85

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

PEF

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2008				
Operating revenues	**$996**	**$1,194**	**$1,428**	**$1,113**
Operating income	**122**	**198**	**236**	**124**
Net income	**67**	**125**	**143**	**50**
2007				
Operating revenues	$1,011	$1,129	$1,456	$1,153
Operating income	117	125	235	109
Net income	61	68	138	50

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

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

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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	(1,535,018)		(1,535,018)	[redacted]	
2	151,545		151,545		
3	(6,982,325)		(6,982,325)		
4	(6,830,780)		(6,830,780)	317,330,866	310,500,086
5	(8,365,798)		(8,365,798)	[redacted]	
6	(8,365,798)		(8,365,798)		
7	225,244		225,244		
8	8,101,688	(562,456)	7,539,232		
9	8,326,932	(562,456)	7,764,476	385,018,788	392,783,264
10	(38,866)	(562,456)	(601,322)	[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	12/31/2008	End of 2008/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)	10,205,245,505	10,202,714,265
4	Property Under Capital Leases	222,959,029	222,959,029
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	10,428,204,534	10,425,673,294
9	Leased to Others		
10	Held for Future Use	35,089,957	35,089,957
11	Construction Work in Progress	2,075,356,574	2,075,356,574
12	Acquisition Adjustments	20,649,139	20,649,139
13	Total Utility Plant (8 thru 12)	12,559,300,204	12,556,768,964
14	Accum Prov for Depr, Amort, & Depl	4,684,684,414	4,683,207,947
15	Net Utility Plant (13 less 14)	7,874,615,790	7,873,561,017
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,562,794,903	4,562,794,903
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	124,456,481	122,980,014
22	Total In Service (18 thru 21)	4,687,251,384	4,685,774,917
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	-2,566,969	-2,566,969
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,684,684,415	4,683,207,948

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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
	1,476,467				14
	1,054,773				15
					16
					17
					18
					19
					20
	1,476,467				21
	1,476,467				22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
	1,476,467				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	12/31/2008	End of 2008/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	5,036,739	72,866
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	5,036,739	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	5,432,526	55,671,197
9	In Reactor (120.3)	104,048,587	888,189
10	SUBTOTAL (Total 8 & 9)	109,481,113	
11	Spent Nuclear Fuel (120.4)	41,325,520	
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	76,991,397	-41,325,520
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	78,851,975	
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	12/31/2008	End of 2008/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
	5,036,739	72,866	3
			4
			5
		72,866	6
			7
		61,103,723	8
		104,936,776	9
		166,040,499	10
	41,325,520		11
			12
-24,367,100		60,032,977	13
		106,080,388	14
			15
			16
			17
			18
			19
			20
			21
			22

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

$5,036,739 transferred to 120.2.

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

$41,325,520 transferred to 120.5.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	8,450,028	
4	(303) Miscellaneous Intangible Plant	125,508,465	-648,157
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	133,958,493	-648,157
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	6,450,314	821,107
9	(311) Structures and Improvements	287,292,786	18,825,706
10	(312) Boiler Plant Equipment	898,979,397	16,981,871
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	466,355,136	14,197,539
13	(315) Accessory Electric Equipment	160,494,704	1,768,068
14	(316) Misc. Power Plant Equipment	31,784,947	890,563
15	(317) Asset Retirement Costs for Steam Production	8,881,847	2,563,413
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,860,239,131	56,048,267
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	-150,918	353
19	(321) Structures and Improvements	225,676,957	8,753,311
20	(322) Reactor Plant Equipment	268,922,087	12,495,882
21	(323) Turbogenerator Units	93,888,191	226,848
22	(324) Accessory Electric Equipment	180,140,996	-4,118
23	(325) Misc. Power Plant Equipment	41,400,429	3,735,210
24	(326) Asset Retirement Costs for Nuclear Production	50,846	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	809,928,588	25,207,486
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	16,544,863	
38	(341) Structures and Improvements	171,266,382	2,287,911
39	(342) Fuel Holders, Products, and Accessories	111,009,452	2,567,624
40	(343) Prime Movers	1,021,913,744	72,759,758
41	(344) Generators	259,257,984	697,190
42	(345) Accessory Electric Equipment	139,579,785	1,155,940
43	(346) Misc. Power Plant Equipment	19,353,930	1,214,062
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,738,926,140	80,682,485
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,409,093,859	161,938,238

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			8,450,028		3
	-408,456		124,451,852		4
	-408,456		132,901,880		5
					6
					7
	-694,786		6,576,635		8
235,894			305,882,598		9
8,945,105			907,016,163		10
					11
6,098,829			474,453,846		12
373,995			161,888,777		13
287,210	25,040		32,413,340		14
	-8,881,847		2,563,413		15
15,941,033	-9,551,593		1,890,794,772		16
					17
	-214,476		-365,041		18
511,271	1,027		233,920,024		19
1,809,535			279,608,434		20
-57,972			94,173,011		21
97,470	25,000		180,064,408		22
1,467,428	-39,257		43,628,954		23
	18,647,131		18,697,977		24
3,827,732	18,419,425		849,727,767		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			16,544,863		37
399,791			173,154,502		38
1,837,837			111,739,239		39
52,911,120			1,041,762,382		40
12,634,620			247,320,554		41
581,158			140,154,567		42
114,479			20,453,513		43
					44
68,479,005			1,751,129,620		45
88,247,770	8,867,832		4,491,652,159		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	12/31/2008	End of 2008/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	70,943,843	8,463,587
49	(352) Structures and Improvements	22,183,416	1,138,225
50	(353) Station Equipment	500,251,034	90,208,052
51	(354) Towers and Fixtures	66,502,240	17,710
52	(355) Poles and Fixtures	378,920,206	55,785,918
53	(356) Overhead Conductors and Devices	258,766,719	46,114,181
54	(357) Underground Conduit	7,010,980	
55	(358) Underground Conductors and Devices	9,611,266	
56	(359) Roads and Trails	3,133,902	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,317,323,606	201,727,673
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	26,088,942	4,449,716
61	(361) Structures and Improvements	24,083,491	2,421,764
62	(362) Station Equipment	425,912,587	42,090,613
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	480,664,662	18,551,231
65	(365) Overhead Conductors and Devices	536,730,033	26,001,473
66	(366) Underground Conduit	204,650,088	12,843,557
67	(367) Underground Conductors and Devices	487,807,417	20,693,423
68	(368) Line Transformers	477,057,510	39,275,969
69	(369) Services	464,610,008	21,955,602
70	(370) Meters	117,505,351	3,052,033
71	(371) Installations on Customer Premises	2,383,459	283,334
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	287,204,325	11,413,080
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,534,697,873	203,031,795
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	10,108,903	
87	(390) Structures and Improvements	109,524,360	1,972,418
88	(391) Office Furniture and Equipment	12,002,325	1,141,096
89	(392) Transportation Equipment	147,636,678	9,459,393
90	(393) Stores Equipment	3,853,371	28,837
91	(394) Tools, Shop and Garage Equipment	14,436,955	1,312,203
92	(395) Laboratory Equipment	2,925,359	41,707
93	(396) Power Operated Equipment	4,149,498	230,469
94	(397) Communication Equipment	64,846,600	2,105,824
95	(398) Miscellaneous Equipment	7,751,639	1,898,280
96	SUBTOTAL (Enter Total of lines 86 thru 95)	377,235,688	18,190,227
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)	379,209,927	18,190,227
100	TOTAL (Accounts 101 and 106)	9,774,283,758	584,239,776
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	9,774,283,758	584,239,776

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
6,502	1,590,718		80,991,646		48
24,339			23,297,302		49
5,992,012	-5,002		584,462,072		50
258,908			66,261,042		51
3,344,025	-139,858		431,222,241		52
2,724,824	8,246		302,164,322		53
			7,010,980		54
			9,611,266		55
			3,133,902		56
					57
12,350,610	1,454,104		1,508,154,773		58
					59
	694,786		31,233,444		60
21,588			26,483,667		61
5,238,728	5,002		462,769,474		62
					63
1,884,201			497,331,692		64
6,346,572			556,384,934		65
217,169	-596,297		216,680,179		66
5,325,360			503,175,480		67
437,814			515,895,665		68
8,728,912	3,171,045		481,007,743		69
			120,557,384		70
			2,666,793		71
					72
4,824,220			293,793,185		73
					74
33,024,564	3,274,536		3,707,979,640		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
139,347			9,969,556		86
1,058,725	17,798		110,455,851		87
248,881			12,894,540		88
30,062,386			127,033,685		89
23,935			3,858,273		90
797,387			14,951,771		91
1,995,384			971,682		92
			4,379,967		93
698,182			66,254,242		94
367,912			9,282,007		95
35,392,139	17,798		360,051,574		96
					97
			1,974,239		98
35,392,139	17,798		362,025,813		99
169,015,083	13,205,814		10,202,714,265		100
					101
					102
					103
169,015,083	13,205,814		10,202,714,265		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	12/31/2008	End of 2008/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	PERRY - CROSS CITY - DUNNELLON	10/87	12/2017	1,046,211
3	PERRY - FLORIDA STATE LINE	12/92	12/2017	1,808,764
4	HIGH SPRINGS - JASPER - FLORIDA STATE LINE	03/96	12/2017	2,584,486
5	BELCHER ROAD SUBSTATION	05/96	12/2009	267,012
6	LYBASS PROPERTY - LEVY COUNTY	12/07	12/2013	27,667,950
7				
8	OTHER LAND AND RIGHTS < $25K EACH	07/90		962,673
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	PERRY - CROSS CITY - DUNNELLON	07/90	12/2017	752,861
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			35,089,957

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	60BT0CRP0 BARTOW REPOWERING	569,199,197
2	60CR0CRP0 CRCA COMMON	442,064,566
3	60LX8D LEVY - Land, long lead Equip and Pre-construction	191,653,401
4	60LU1D STEAM GENERATOR MASTER	139,938,944
5	60CRN5CRP0 CR U5 FGD	114,497,798
6	60CRN4CRP0 CR U4 FGD	104,780,075
7	60CRN5CRPO CR U5 SCR/LNB	98,585,713
8	60LU1D CR3 POWER UPRATE	93,577,850
9	60CRNCRP0 UNIT 4 SCR - CAIR	88,194,689
10	60KK8-1910T1 BARTOW NE UG	86,811,535
11	60LG7 NNP COLA DEVLOP PEF	27,535,518
12	60LG7D - PEF COLA	24,532,679
13	60CRN0CRP0 UREA TO AMMONIA	23,659,672
14	60CR5P0 CR UNIT 5 ESP	22,308,204
15	60KK8-1910S2 NORTHEAST SUB TER	15,933,857
16	60CRN5CRP0 CR5 TURBINE PROJECT	14,103,791
17	60KK8-1874T1 WLW RECONDUCTOR	14,076,369
18	60CRN4CRP0 CR UNIT 4 ESP	13,538,616
19	60KK8-1124D1 SPRING LK TRANSF	8,911,166
20	60GB9D CR3 LICENSE RENEWAL MAS	7,422,340
21	60KK8-1579S1 AVON PARK	6,690,834
22	60LG7D - PEF ENG/DESIGN	6,178,359
23	60KK8-1933D3 51ST ST XFMR	6,113,500
24	60KK8-1935T1 NE 40TH REBUILD	6,088,233
25	60CR4CRP3 CR4 TURBINE PROJECT	5,265,356
26	60KK8-1005T2 BOGGY MARSH	5,083,504
27	60KK8-1650D1 ZEPHYRHILLS NORTH	4,355,708
28	60KK8-1579T1 AF2 CONVERT 230KV	4,177,793
29	60CRN0CRP4 GYPSUM HANDLING	3,439,402
30	60CR4CRP4 CT CATHODIC PROT	3,368,371
31	60GB9D FP CODE CONF PROJECT	3,278,443
32	60KK8-1005T1 AVALON-GIFFORD	3,116,370
33	60LU1D HOT LEG ALLOY 600 MITIG	3,012,286
34	VMS SOFTWARE	2,988,526
35	60KK8-1857T4 OCOEE-WINTER GRDN	2,924,048
36	60034-2041D1 VINELAND CAP INCR	2,754,229
37	60034-1315D1 ORANGE BLOSSOM	2,281,087
38	60CR5CRP4 CONDENSER TUBE REPL	2,260,555
39	60X00D 09 VEH LSED ASSET	2,237,368
40	60KK8-1525T1 INT CITY-LOUGHMAN	2,126,248
41	60KK8D 1931S2 HAINES CITY EAST	1,911,267
42	60034-1318D1 BEACON HILL	1,769,586
43	TOTAL	2,075,356,574

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	60KK8-1781T1 NORTH EAST-32ND	1,746,219
2	60CR0CRP4 RAILROAD TRACKS YR1	1,688,740
3	60034D-1767D1 PINELLAS WATER	1,659,457
4	CP ECRC DEB TANK 1 FDEP WORK	1,644,231
5	CATALYST 221 - PEF	1,551,866
6	60KK8-1794T1 PORT ST JOE-APALA	1,308,672
7	60GB9D SPENT FUEL DRY CASK	1,147,791
8	60KK8D 1874D1 DUNDEE SUB	1,132,912
9	60GB9D TRNG SIMULATOR UPG	1,114,903
10	60KK8-1005S1 GIFFORD NEW SUB	1,047,835
11	60KK8-1857D1 OCOEE REPL BRKR	1,044,596
12	60KK8D 1785T1 GIFFORD 230KV	1,024,713
13	CR3 Contra CWIP	-4,736,965
14	Levy BaseLoad Contra CWIP	-168,902,772
15	Other Minor Projects	50,137,323
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		
42		
43	TOTAL	2,075,356,574

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	4,421,851,627	4,421,851,627		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	301,087,762	301,087,762		
4	(403.1) Depreciation Expense for Asset Retirement Costs	354,972	354,972		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts	917,304	917,304		
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock - Oil & Rail Cars	2,269,274	2,269,274		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	304,629,312	304,629,312		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	169,015,083	169,015,083		
13	Cost of Removal	30,840,181	30,840,181		
14	Salvage (Credit)	38,126,482	38,126,482		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	161,728,782	161,728,782		
16	Other Debit or Cr. Items (Describe, details in footnote):	-1,957,254	-1,957,254		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,562,794,903	4,562,794,903		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,430,111,990	1,430,111,990		
21	Nuclear Production	600,740,465	600,740,465		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	527,139,596	527,139,596		
25	Transmission	475,762,867	475,762,867		
26	Distribution	1,400,066,245	1,400,066,245		
27	Regional Transmission and Market Operation				
28	General	128,973,740	128,973,740		
29	TOTAL (Enter Total of lines 20 thru 28)	4,562,794,903	4,562,794,903		

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	12/31/2008	2008/Q4

FOOTNOTE DATA

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

Provision for Steam 312.0 Rail cars	$1,587,831
Provision for Steam 311.0-315.0 & 316.3 Bartow Anclote Pipeline	$ 681,443
Total:	$2,269,274

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

Adjustments to Reserve:

Clearing OVerhead	$ (876,637)
Other Adjustments & Transfers	$ (1,080,617)
Total:	$ (1,957,254)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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)	245,349,474	326,907,773	
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)	168,284,311	131,197,757	Various
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	24,765,470	71,315,414	Power Supply
8	Transmission Plant (Estimated)	1,528,817	4,422,282	Transmission
9	Distribution Plant (Estimated)	6,288,609	18,592,364	Customer Service
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	622,629	1,654,446	Various
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	201,489,836	227,182,263	
13	Merchandise (Account 155)	674,288	505,165	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)	33,546,843	22,069,958	Various
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	481,060,441	576,665,159	

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

Account 154 Plant Materials and Operating Supplies includes an Inventory reserve account, credit balance of $1,363,030. During 2007, $3,409,248 was charged and $2,942,507 was credited against this reserve account. Current reserve levels are sufficient based on current inventory reviews.

Account 154 Plant Materials and Operating Supplies is a net balance and excludes the co-owned inventory balance of $4,980,823. Co-owned inventory accounts include Crystal River Unit 3 valued at $3,169,075 and Intercession City, Siemens Unit 11 valued at $1,811,747 at the end of 2007.

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

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

Account 154 Plant Materials and Operating Supplies includes an Inventory reserve account, credit balance of $1,082,359. During 2008, $2,689,989 was charged and $2,409,318 was credited against this reserve account. Current reserve levels are sufficient based on current inventory reviews.

Account 154 Plant Materials and Operating Supplies is a net balance and excludes the co-owned inventory balance of $5,182,150. Co-owned inventory accounts include Crystal River Unit 3 valued at $3,354,605 and Intercession City, Siemens Unit 11 valued at $1,827,545 at the end of 2008.

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

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

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

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

Account 163 - Stores Expense Undistributed - Allocations accounts were charged with $2,916,493 and credited with $2,437,397 for a net charge of $479,096 during 2008. These charges to operations, maintenance and capital accounts were to record various inventory adjustments for 2008.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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)	2009 No. (d)	2009 Amt. (e)
1	Balance-Beginning of Year	175,711.00	9,376,113	151,822.00	7,211,510
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Allowances Acquired from	27,834.00	23,027,500	7,485.00	28,589,165
10					
11					
12					
13					
14					
15	Total	27,834.00	23,027,500	7,485.00	28,589,165
16					
17	Relinquished During Year:				
18	Charges to Account 509	110,564.00	14,747,996		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Allowances Transferred to	10,500.00	1,531,528		
23					
24					
25					
26					
27					
28	Total	10,500.00	1,531,528		
29	Balance-End of Year	82,481.00	16,124,089	159,307.00	35,800,675
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	3,343.00		3,343.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year	3,343.00		3,343.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	1,697.00	671,884		
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	12/31/2008	End of 2008/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.

2010		2011		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
144,310.00	3,221,250	145,235.00	3,095,475	2,291,509.00	8,664,525	2,908,587.00	31,568,873	1
								2
								3
				143,285.00		143,285.00		4
								5
								6
								7
								8
5,935.00	2,790,775	6,710.00	4,628,301	18,325.00	2,376,925	66,289.00	61,412,666	9
								10
								11
								12
								13
								14
5,935.00	2,790,775	6,710.00	4,628,301	18,325.00	2,376,925	66,289.00	61,412,666	15
								16
								17
						110,564.00	14,747,996	18
								19
								20
								21
						10,500.00	1,531,528	22
								23
								24
								25
								26
								27
						10,500.00	1,531,528	28
150,245.00	6,012,025	151,945.00	7,723,776	2,453,119.00	11,041,450	2,997,097.00	76,702,015	29
								30
								31
								32
								33
								34
								35
3,343.00		3,343.00		67,600.00		80,972.00		36
								37
								38
								39
3,343.00		3,343.00		67,600.00		80,972.00		40
								41
								42
								43
				1,693.00	234,317	3,390.00	906,201	44
								45
								46

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

	Added to Future Yr Quantity
SO2- added 30th Year	119,141
NOX Annual- 2012 only	16,182
NOX Seasonal - 2012 only	7,962
	143,285

Schedule Page: 228 Line No.: 9 Column: a

PEF 2008 Form 1 - Line 9
Names of vendors/transferors of allowances acquired

AES EASTERN ENERGY	SWAP	NOX
DUKE ENERGY INDIANA	SWAP	NOX
EVOLUTION MARKETS, AS AGENT FOR KELSON ENERGY	SWAP	NOX
KOCH SUPPLY AND TRADING	SWAP	NOX
LOUIS DREYFUS ENERGY SERVICES	SWAP	NOX
AEP SERVICE CORP	PURCHASE	NOX
ASSOCIATED ELECTRIC COOPERATIVE	PURCHASE	NOX
BEAR ENERGY, LP	PURCHASE	NOX
CE2 ENVIRONMENTAL MARKETS, LP	PURCHASE	NOX
CE2 ENVIRONMENTAL OPPORTUNITIES 1, LP	PURCHASE	NOX
CONSTELLATION ENERGY COMMODITIES GROUP, INC.	PURCHASE	NOX
DAYTON POWER AND LIGHT COMPANY	PURCHASE	NOX
DTE COAL SERVICES	PURCHASE	NOX
DUKE ENERGY INDIANA	PURCHASE	NOX
DUKE ENERGY OHIO	PURCHASE	NOX
FORTISTAR NORTH TONAWANDA	PURCHASE	NOX
KOCH SUPPLY AND TRADING	PURCHASE	NOX
LOCKPORT ENERGY ASSOCIATES	PURCHASE	NOX
LOUIS DREYFUS ENERGY SERVICES	PURCHASE	NOX
LSP WHITEWATER LP	PURCHASE	NOX
MORGAN STANLEY	PURCHASE	SO2
NRG POWER MARKETING, INC	PURCHASE	NOX
SEMPRA ENERGY TRADING	PURCHASE	NOX
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY	PURCHASE	NOX
VIRGINIA ELECTRIC & POWER COMPANY	PURCHASE	NOX

Schedule Page: 228 Line No.: 22 Column: a

PEF 2008 Form 1 - Line 22
Names of purchasers/transferees of allowances disposed

TRANS-ALTA	SWAP	SO_2

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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	1,990,136	13,668,566
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL	16,963,061			1,990,136	13,668,566

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Proposed Nuclear Units				
23	Levy County, FL				
24	Impact Study Phase 2	114,147			
25					
26					
27	PEF Resource Planning				
28	(Ten Yr Site Plan, Generation				
29	Fuel Forecast)	558,570			
30					
31					
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	12/31/2008	End of 2008/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS: Written off During the Quarter/Year Account Charged	CREDITS: Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Accumulated Deferred Taxes - FAS 109	128,394,000	46,212,000	182.3 & 41	12,032,530	162,573,470
2	as temporary differences occur.					
3						
4	Load Control Switches - Investment	6,617,037	6,394,600	1823310	1,169,297	11,842,340
5	Load Control Switches - Amortization	(2,078,190)	722,311	9080120	1,852,391	-3,208,270
6						
7	Sebring Transition Rider	1,895,325	4,677	1861904	1,900,002	
8	Sebring - Over(Under) Recovered	(1,120,970)	1,932,095	4044002	811,125	
9						
10	Interest on Tax Deficiency	(628,430)	10,835,436	4310024	10,207,006	
11						
12	Deferred GPIF Asset	607,201	2,167,933	4560096	607,201	2,167,933
13	Deferred Fuel Expense - Full Req	6,338,845	9,677,799	5572002	10,440,763	5,575,881
14	Deferred Fuel Expense - Current Year		213,505,631	5572002	85,028,453	128,477,178
15	Deferred Capacity Expense - Prior Year	3,381,972	9,236,664	5572001	14,799,865	-2,181,229
16	Deferred Capacity Expense - Current Year	9,236,664	24,492,268	5572001	33,728,932	
17						
18	Deferred Environmental Cost Recovery		65,413,088	9350003	57,164,897	8,248,191
19	Accrued Environmental Cost Recovery	29,849,147	15,941,766	2284800	24,473,549	21,317,364
20						
21	Florida Minimum Pension Liability	85,507,393	439,155,321	2283151-70	4,951,052	519,711,662
22						
23	Regulatory Asset Derivative MTM Oil	13,787,623	612,233,316	2543015-17	25,120,417	600,900,522
24						
25	Regulatory Asset - FAS 143 Asbestos	239,742	5,821,484			6,061,226
26						
27	Deferred Levy Nuclear - Current Year		180,942,559			180,942,559
28	Deferred CR3 NCR - Current Year		8,546,392			8,546,392
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	282,027,359	1,653,235,340		284,287,480	1,650,975,219

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	190,734	9,848,775	Various	9,863,701	175,808
2	Southern Company Capacity	803,433				803,433
3	NFPP Generation Study	81,478		Various	81,478	
4	Longwood Hydrogen Vehicle	50,672				50,672
5	Vandolah Generation Study	70,060		Various	70,060	
6	FL Rate Case		426,937	Various	94,420	332,517
7	Vacation Pay Accrual	5,959,012	7,435,643	242	5,959,011	7,435,644
8	Labor Accrual	1,907,734	35,553,992	242	34,629,865	2,831,861
9	G2 Energy Pre-construction		716,012	Various	456,367	259,645
10	Fay Storm		33,206,793	Various	23,438,037	9,768,756
11	Zephyrhills		400,000	Various		400,000
12	F&H Gulf Blvd Project		227,688	Various	16,866	210,822
13	Coal Mine Safety		1,555,042	Various	1,309,169	245,873
14	Gov Imposition		14,259	Various		14,259
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						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	9,063,123				22,529,290

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	41,489,000	42,844,000
3	LIFE/MEDICAL BENEFITS	111,652,000	114,831,000
4	UNAMORTIZED INVESTMENT TAX CREDIT	6,730,000	4,439,000
5	REGULATORY LIABILITY	14,958,000	12,215,000
6	NUCLEAR DECOMMISSIONING	102,076,000	40,023,000
7	OTHER	181,629,900	428,421,374
8	TOTAL Electric (Enter Total of lines 2 thru 7)	458,534,900	642,773,374
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)	458,534,900	642,773,374

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	12/31/2008	End of 2008/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				
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				
42				

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
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
						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
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	ACCOUNT 211 - MISCELLANEOUS PAID IN CAPITAL	
2	Donations by General Gas & Electric Corporation (Former Parent)	419,213
3	Excess of Stated Value of 3,000,000 shares of Common Stock	
4	exchanged for 857, 143 shares at $7.50 par value Common Stock and	
5	miscellaneous adjustments applicable to exchange	326,032
6	Excess of Net Worth of Assets at date of Merger (12/31/43)	
7	over stated value of Common Stock issued therefore	1,167,518
8	Florida Public Service 4% Series "C" Bonds with called premium and	
9	interest held by General Gas and Electric Corporation	65,210
10	Reversal of over accrual of Federal Income Tax applicable to period	
11	prior to January 1, 1944	262,837
12	Transfer from Earned Surplus amount equivalent to Preferred Stock	
13	Dividends prior to 12/31/43 which on an accrual basis were applicable	
14	to 1944	92,552
15	To write off unamortized debt discount, premium and expense applicable	-979,793
16	to Bonds refunded in prior years	
17	Adjustment of original cost of Florida Public Service Company	
18	resulting in examination by Federal Power Commission	-63,027
19	Adjustment in carrying value of Georgia Power & Light Company Common	
20	Stock occasioned by the subsidiary company's increase in capital	
21	surplus	33,505
22	Capital Contribution from Parent Company	739,992,013
23	Other Miscellaneous adjustments	45,211
24	Payroll taxes associated with stock option exercises	1,260,482
25	Misc PIC - Stock Options	655,780
26	Misc PIC - Performance Share Sub Plan (PSSP)	10,015,254
27	Misc PIC - Restricted Stock Units (RSU)	8,709,240
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	762,002,027

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	3,291,598
12			915,000 D
13	Medium Term Note (Sebring) - 6.67%	30,700,000	280,604
14			
15	Medium Term Note - 6.75%	150,000,000	5,528,498
16			436,500 D
17	Series A Senior Note - Floating Rate	450,000,000	1,555,087
18			590,625 D
19	Pollution Control Bonds (Citrus) 2002A	108,550,000	2,356,705
20			
21	Pollution Control Bonds (Citrus) 2002B	100,115,000	2,081,983
22			
23	Pollution Control Bonds (Citrus) 2002C	32,200,000	756,175
24	RCA - 5 Year		1,009,474
25	First Mortgage Bonds - 6.35%	500,000,000	6,708,137
26			660,000 D
27	First Mortgage Bonds - 5.80%	250,000,000	2,959,477
28			672,500 D
29	First Mortgage Bonds - 5.65%	500,000,000	5,559,462
30			1,805,000 D
31	First Mortgage Bonds - 6.40%	1,000,000,000	13,136,457
32			4,220,000 D
33	TOTAL	4,751,565,000	73,720,230

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
7/18/01	7/15/11	7/18/01	7/15/11	300,000,000	19,950,000	1
						2
2/09/93	2/01/08	2/09/93	2/01/08		458,333	3
						4
2/21/03	3/1/13	2/21/03	3/1/13	425,000,000	20,400,000	5
						6
2/21/03	2/15/33	2/21/03	2/15/33	225,000,000	13,275,000	7
						8
11/21/03	12/1/15	11/21/03	12/1/15	300,000,000	15,300,000	9
						10
5/16/05	6/1/10	5/16/05	6/1/10	300,000,000	13,500,000	11
						12
4/20/93	4/1/08	4/20/93	4/1/08		31,680	13
						14
2/13/98	2/01/28	2/13/98	2/01/28	150,000,000	10,125,000	15
						16
12/13/05	11/14/08	12/13/05	11/14/08		10,339,287	17
						18
8/13/02	1/01/27	8/20/02	1/01/27	108,550,000	5,512,332	19
						20
7/24/02	1/01/22	7/24/02	1/01/22	100,115,000	5,151,159	21
						22
8/13/02	1/01/18	8/13/02	1/01/18	32,200,000	1,673,237	23
3/28/05	3/28/11	3/28/05	3/28/11			24
9/12/07	9/15/37	9/12/07	9/15/37	500,000,000	32,068,549	25
						26
9/12/07	9/15/17	9/12/07	9/15/17	250,000,000	14,915,729	27
						28
6/15/08	6/15/18	6/15/08	6/15/18	500,000,000	14,490,290	29
						30
6/15/08	6/15/38	6/15/08	6/15/38	1,000,000,000	33,290,337	31
						32
				4,190,865,000	210,480,933	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	12/31/2008	End of 2008/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)	385,018,788
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	153,721,530
11		
12	Deductions Recorded on Books Not Deducted for Return	1,585,306,243
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	-2,007,907,945
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	116,138,616
28	Show Computation of Tax:	
29	Provision for Federal Income Tax at 35%	40,648,515
30	True up Entries and Other Tax Benefits	-1,650,404
31	Total Federal Income Tax Provision (409120F - 409220F) True up Entries	38,998,111
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
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	12/31/2008	End of 2008/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	-39,253,520		38,998,111	36,146,195	
3	FICA	10,881		24,365,111	24,360,693	
4	Unemployment	15,710		258,335	267,931	
5	Special Fuel Tax					
6	Excise Tax					
7	Highway Use					
8	Payroll Tax	1,835,384			-22,764	
9	SUBTOTAL	-37,391,545		63,621,557	60,752,055	
10						
11	STATE TAXES					
12	Income	600,820		11,891,835	21,583,020	
13	Income Tax Subsidiary					
14	Gross Receipts	6,900,844		98,667,483	98,228,791	
15	Unemployment	61,749		833,818	875,848	
16	Intangibles					
17	Regulatory Assessment	1,687,852		2,947,228	3,053,477	
18	Sales Tax-Company Use	15,545		142,331	144,654	
19	SUBTOTAL	9,266,810		114,482,695	123,885,790	
20						
21	COUNTY & LOCAL TAXES					
22	Property-County & Local			92,433,096	92,432,516	
23	FL Privilege License					
24	Franchise-Local	6,631,764		94,288,243	93,870,165	
25						
26						
27	Adj-Use Tax on Purchases					
28	SUBTOTAL	6,631,764		186,721,339	186,302,681	
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-21,492,971		364,825,591	370,940,526	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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
-36,401,604		36,540,063			2,458,048	2
15,299		20,916,779			3,448,333	3
6,115					258,335	4
						5
						6
						7
1,858,148						8
-34,522,042		57,456,842			6,164,716	9
						10
						11
-9,090,366		11,486,179			405,656	12
						13
7,339,536		98,667,483				14
19,720					833,818	15
						16
1,581,603		2,947,228				17
13,222		142,331				18
-136,285		113,243,221			1,239,474	19
						20
						21
580		92,305,320			127,776	22
						23
7,049,842		94,289,353			-1,110	24
						25
						26
						27
7,050,422		186,594,673			126,666	28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
-27,607,905		357,294,736			7,530,856	41

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

Page 112, Line 37, Column d

The difference between the Taxes Accrued amount on Page 112, Line 42 and Taxes Accrued on Page 262 - 263, Col. (b) & (g) are for exclusions of Sales Taxes per instruction #1 on Page 262.

Taxes Accrued, P. 112, Line 42	(21,197,682)	(27,105,282)
State Sales Tax on Purchases	(289,398)	(491,012)
County Sales Tax on Purchases	(5,891)	(11,610)
	(21,492,971)	(27,607,904)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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%	17,446,508			4114001	5,940,000	
6							
7							
8	TOTAL	17,446,508				5,940,000	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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
11,506,508	27 years		5
			6
			7
11,506,508			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	240,274	131	323,623	83,349	
2	Wholesale Deposits - SECI	6,810,000	131	1,310,000		5,500,000
3	Wholesale Deposits - Other	238,459	253	47,309	30,000	221,150
4	Wholesale Deposits - FMPA	1,300,000	131	40,000		1,260,000
5	Interest on Tax Deficiency	14,557,216	various	5,630,821	6,359,423	15,285,818
6	12K Basket Upgrade		107		6,627,248	6,627,248
7	Cable and Other Deposits	210,228	131, 242	2,396,012	4,146,685	1,960,901
8	Deferred Rent Expense	561,939	242, 931	222,222		339,717
9	Franchise Settlements	1,584,000	131	254,000		1,330,000
10	PEP Lease Incentives	3,715,217	242	128,258		3,586,959
11	Feasibility Study	818,290	186	272,787	456,704	1,002,207
12	PTC Fiber 400 Indemnification	7,653,124	242	527,640		7,125,484
13	Joint Owner	-505,754	various	9,468,456	8,067,330	-1,906,880
14	Various	98,774	various	5,600,868	5,511,021	8,927
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						
42						
43						
44						
45						
46						
47	TOTAL	37,281,767		26,221,996	31,281,760	42,341,531

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	6,186,000		2,103,000
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	6,186,000		2,103,000
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	6,186,000		2,103,000
18	Classification of TOTAL			
19	Federal Income Tax	5,304,000		1,806,000
20	State Income Tax	882,000		297,000
21	Local Income Tax			

NOTES

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
						4,083,000	4
							5
							6
							7
						4,083,000	8
							9
							10
							11
							12
							13
							14
							15
							16
						4,083,000	17
							18
						3,498,000	19
						585,000	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	12/31/2008	End of 2008/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	441,093,000	93,022,467	42,756,000
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	441,093,000	93,022,467	42,756,000
6	Other			
7	Other			
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	441,093,000	93,022,467	42,756,000
10	Classification of TOTAL			
11	Federal Income Tax	378,886,000	83,950,230	37,159,000
12	State Income Tax	62,207,000	9,072,237	5,597,000
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) 12/31/2008	Year/Period of Report End of 2008/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (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
	273,000	Various	4,432,160	Various	60,618,840	547,273,147	2
							3
							4
	273,000		4,432,160		60,618,840	547,273,147	5
							6
							7
							8
	273,000		4,432,160		60,618,840	547,273,147	9
							10
	237,000		4,348,460		52,779,270	473,871,040	11
	36,000		83,700		7,839,570	73,402,107	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: g

Adjustments to 282 - Various Accounts

Debits to 282 - Credits to Various Accounts		Credits to 282 - Debits to Various Accounts	
19011FE	(3,976,483)	28315FE	45,214,186
2340063	(432,677)	409120F	6,198,084
28311FL	(23,000)	28311FE	1,367,000
		28315ST	7,343,357
		409120J	496,213
TOTAL	(4,432,160)	TOTAL	60,618,840

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	49,521,000	13,185,000	
4				
5				
6				
7				
8	Other	320,651,542	604,965,000	266,837,000
9	TOTAL Electric (Total of lines 3 thru 8)	370,172,542	618,150,000	266,837,000
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)	370,172,542	618,150,000	266,837,000
20	Classification of TOTAL			
21	Federal Income Tax	317,884,568	529,948,000	228,800,000
22	State Income Tax	52,287,975	88,202,000	38,037,000
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) 12/31/2008	Year/Period of Report End of 2008/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				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)		
							1
							2
						62,706,000	3
							4
							5
							6
							7
		Various	71,615,200			587,164,342	8
			71,615,200			649,870,342	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
			71,615,200			649,870,342	19
							20
			61,129,185			557,903,383	21
			10,486,016			91,966,959	22
							23

NOTES (Continued)

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

Adjustments to 283 - Various Accounts

Debits to 283 - Credits to Various Accounts

19011FE	(15,915,000)
28210FL	(2,396,000)
23612FL	(746,659)
28215FE	(45,214,185)
28215ST	(7,343,357)
Total Credits	(71,615,201)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	38,776,516	4111000	7,112,000		31,664,516
2	Period of Amortization occurs as					
3	temporary differences occur.					
4						
5	Regulatory Liability Fuel	14,181,482	5572002	14,402,775	5,033,945	4,812,652
6	Deferred Fuel Revenue - Current Year	123,704,902	5572002	214,552,258	90,847,356	
7	Deferred Fuel Revenue - Prior Year	28,864,614	5572002	169,376,546	123,704,902	-16,807,030
8	Deferred Capacity Revenue - Cur Yr.		5572001	3,388,449	19,029,848	15,641,399
9						
10	Deferred Environmental Cost Recovery	4,667,390	9350003	4,667,390		
11						
12	ARO - Nuclear Decom Trust Unrl Gains	162,615,416	1289191	178,167,715	22,749,414	7,197,115
13	ARO - SFAS 143 Nuclear Decom	94,971,669	4073002	27,296,111	3,540,811	71,216,369
14	ARO - SFAS 143 Asbestos	1,405,375	4073002	1,139,707	4,271,840	4,537,508
15						
16	Auctioned S02 Allowance	2,019,940	407004	862,888	906,201	2,063,253
17						
18	Winter Park Stranded Costs-6/05-12/10	2,974,976	4560001	1,421,004		1,553,972
19						
20	Regulatory Liability Derivative MTM Oil	179,863,591	1823015	1,149,348,092	995,443,003	25,958,502
21						
22	Deferred Energy Conservation	14,173,795	9080110	9,630,592	1,952,354	6,495,557
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	668,219,666		1,781,365,527	1,267,479,674	154,333,813

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	2,273,649,602	2,363,141,608
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,127,543,766	1,153,050,552
5	Large (or Ind.) (See Instr. 4)	308,064,952	317,415,092
6	(444) Public Street and Highway Lighting	1,841,868	1,892,499
7	(445) Other Sales to Public Authorities	291,612,950	302,878,128
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,002,713,138	4,138,377,879
11	(447) Sales for Resale	548,740,574	435,681,011
12	TOTAL Sales of Electricity	4,551,453,712	4,574,058,890
13	(Less) (449.1) Provision for Rate Refunds	1,474,329	1,675,074
14	TOTAL Revenues Net of Prov. for Refunds	4,549,979,383	4,572,383,816
15	Other Operating Revenues		
16	(450) Forfeited Discounts	22,775,140	23,058,391
17	(451) Miscellaneous Service Revenues	24,254,337	25,044,986
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	82,583,176	79,006,174
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	51,298,452	-6,970,035
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	180,911,105	120,139,516
27	TOTAL Electric Operating Revenues	4,730,890,488	4,692,523,332

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

ELECTRIC OPERATING REVENUES (Account 400)

5. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
19,328,406	19,911,884	1,449,041	1,442,854	2
				3
12,138,923	12,183,637	162,569	162,837	4
3,786,296	3,819,403	2,587	2,668	5
26,271	26,102	1,652	1,692	6
3,275,813	3,340,612	23,062	22,379	7
				8
				9
38,555,709	39,281,638	1,638,911	1,632,430	10
6,777,353	5,930,039	24	21	11
45,333,062	45,211,677	1,638,935	1,632,451	12
				13
45,333,062	45,211,677	1,638,935	1,632,451	14

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

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

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Services	19,328,406	2,273,649,602	1,449,041	13,339	0.1176
2						
3	Commercial and Industrial Service	15,925,219	1,435,608,718	165,156	96,425	0.0901
4						
5	Public Street and Highway	26,271	1,841,868	1,652	15,903	0.0701
6	Lighting					
7	Other Sales to Public Authorities	3,275,813	291,612,950	23,062	142,044	0.0890
8						
9	Total Sales to Ultimate Customers	38,555,709	4,002,713,138	1,638,911	23,525	0.1038
10						
11						
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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

SALES FOR RESALE (Account 447)

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

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

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

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	CITY OF BARTOW	RQ	TARIFF NO. 9	56	56	55
2	CITY OF CHATTAHOOCHEE	RQ	FERC NO. 126	5	5	5
3	CITY OF HOMESTEAD	RQ	TARIFF NO. 9	34	35	27
4	CITY OF KISSIMMEE	RQ	FERC NO. 120			
5	CITY OF DORA	RQ	FERC NO. 127	19	19	19
6	CITY OF NEW SMYRNA BEACH	RQ	FERC NO. 144	15	15	15
7	CITY OF QUINCY	RQ	TARIFF NO. 01	20	20	20
8	CITY OF ST. CLOUD	RQ	FERC NO. 121			
9	CITY OF TALLAHASSEE	RQ	FERC NO. 178	11	11	11
10	CITY OF WILLISTON	RQ	FERC NO. 124	7	7	7
11	CITY OF WINTER PARK	RQ	FERC NO. 191	81	81	81
12	FLORIDA MUNICIPAL POWER AGENCY	RQ	FERC NO. 107	69	66	66
13	REEDY CREEK IMPROVEMENT DISTRICT	RQ	FERC NO. 118	98	98	98
14	SEMINOLE ELECTRIC COOPERATIVE, INC	RQ	FERC NO. 106	868	871	849
	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) 12/31/2008	Year/Period of Report End of 2008/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.
301,435	6,123,418	18,370,450	1,560	24,495,428	1
32,319	647,919	1,907,555	3,168	2,558,642	2
218,353	4,632,543	11,622,907		16,255,450	3
			8,004	8,004	4
97,471	2,104,619	5,979,004		8,083,623	5
92,321	1,890,360	5,131,051	996	7,022,407	6
113,051	2,117,916	6,879,571	528	8,998,015	7
			996	996	8
100,140	-209,600	4,363,532		4,153,932	9
35,427	614,973	2,049,621	264	2,664,858	10
446,038	8,095,881	27,829,681		35,925,562	11
326,648	8,566,042	20,131,900	79,920	28,777,862	12
818,800	14,714,730	37,605,301	33,984	52,354,015	13
2,945,590	80,679,722	187,040,130	899,798	268,619,650	14
6,619,497	155,319,591	380,993,419	1,029,218	537,342,228	
157,856	0	12,121,985	-723,639	11,398,346	
6,777,353	**155,319,591**	**393,115,404**	**305,579**	**548,740,574**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SOUTHEASTERN POWER ADMIN	RQ	FERC NO. 65	17	16	12
2	TAMPA ELECTRIC COMPANY	RQ	FERC NO. 07	100	100	98
3	CITY OF GAINSVILLE	RQ	FERC NO. 88	51	51	47
4						
5						
6						
7						
8	NON-REQUIREMENTS SERVICE					
9	ALABAMA ELECTRIC CO-OP	OS	FERC NO. 148			
10	CONOCO PHILLIPS	OS	FERC NO.10			
11	COBB ELECTRIC MEMBERSHIP CORP	OS	FERC NO. 10			
12	CARGILL-ALLIANT	OS	FERC NO. 8			
13	DTE ENERGY TRADING	OS	FERC NO. 176			
14	DUKE POWER COMPANY	OS	FERC NO. 10			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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.
64,917	511,405	3,826,814		4,338,219	1
766,128	17,534,239	35,659,185		53,193,424	2
260,859	7,295,424	12,596,717		19,892,141	3
					4
					5
					6
					7
					8
2,000		110,386		110,386	9
					10
28,878		1,788,005		1,788,005	11
12,425		809,746		809,746	12
					13
128		7,424		7,424	14
6,619,497	155,319,591	380,993,419	1,029,218	537,342,228	
157,856	0	12,121,985	-723,639	11,398,346	
6,777,353	**155,319,591**	**393,115,404**	**305,579**	**548,740,574**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	FLORIDA MUNICIPAL POWER AGENCY	OS	FERC NO. 105			
2	FLORIDA POWER & LIGHT CO	OS	FERC NO. 81/02			
3	GAINESVILLE REGIONAL UTILITIES	OS	FERC NO. 88			
4	HOMESTEAD, CITY OF	OS	FERC NO. 82			
5	LAKELAND, CITY OF	OS	FERC NO 92			
6	NEW SMYRNA BEACH, CITY OF (1)	OS	FERC NO. 104			
7	OGLETHORPE	OS	FERC NO. 139			
8	ORLANDO UTILITIES COMMISSION	AD	FERC NO. 86			
9	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86			
10	PJM INTERCONNECTION, LLC	OS	PJM			
11	REEDY CREEK UTILITIES	OS	FERC NO. 119			
12	SOUTH CAROLINA ELEC & GAS CO	OS	FERC NO. 8/10			
13	SEMINOLE ELECTRIC COOP INC.	AD	FERC NO. 128			
14	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128			
	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) 12/31/2008	Year/Period of Report End of 2008/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.
1,625		99,130		99,130	1
200		11,844		11,844	2
207		68,879		68,879	3
					4
75		5,294		5,294	5
2,150		574,223	-106,099	468,124	6
4,652		394,428		394,428	7
725			51,900	51,900	8
125		9,355		9,355	9
19,771		1,080,689		1,080,689	10
1,673		63,759		63,759	11
					12
			60	60	13
28,081		2,867,731		2,867,731	14
6,619,497	155,319,591	380,993,419	1,029,218	537,342,228	
157,856	0	12,121,985	-723,639	11,398,346	
6,777,353	**155,319,591**	**393,115,404**	**305,579**	**548,740,574**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SOUTHERN COMPANY SERVICES	OS	FERC NO. 111			
2	TALLAHASSEE, CITY OF (1)	OS	FERC NO. 122			
3	THE ENERGY AUTHORITY	OS	FERC NO. 175			
4	TAMPA ELECTRIC CO	OS	FERC NO. 80			
5	TENNESSEE VALLEY AUTHORITY	OS	FERC NO. 138			
6	MORGAN STANLEY	OS	FERC NO. 177			
7	CONSTELLATION ENERGY COMMODITIES	OS	FERC No. 8			
8	AMERICAN ELECTRIC POWER SERVICE	OS	FERC No. 8			
9	FLORIDA MUNICIPAL POWER AGENCY	AD	FERC NO. 105			
10	RAINBOW ENERGY MARKETING CORP	OS				
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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.
1,400		58,944		58,944	1
1,992		847,791	-617,600	230,191	2
12,401		837,427		837,427	3
18,973		1,207,086		1,207,086	4
16,947		1,026,106		1,026,106	5
					6
3,765		235,483		235,483	7
					8
-725			-51,900	-51,900	9
388		18,255		18,255	10
					11
					12
					13
					14
6,619,497	155,319,591	380,993,419	1,029,218	537,342,228	
157,856	0	12,121,985	-723,639	11,398,346	
6,777,353	**155,319,591**	**393,115,404**	**305,579**	**548,740,574**	

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

Non-requirement Service is either:
(1) Economy Interchanges Sales for
pages 310.1 lines 9-14,
pages 310.2 lines 1-14,
pages 310.3 lines 1-5 and 7-9

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

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

2008 OS Sales for New Smyrna Beach, City of includes ($106,099) capacity credit

Schedule Page: 310.2 Line No.: 8 Column: a

OUT OF PERIOD ADJUSTMENT - ORLANDO UTILITIES COMMISSION - 725MW @ $51,900

Schedule Page: 310.3 Line No.: 2 Column: a

2008 OS Sales for Tallahassee, City of includes ($617,600) capacity credit

Schedule Page: 310.3 Line No.: 9 Column: a

Out-of-period adjustment - Florida Municipal Power Agency - (725)mw;($51,900)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	7,921,409	1,398,411
5	(501) Fuel	952,698,616	919,875,212
6	(502) Steam Expenses	8,621,084	6,951,033
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	34,116	1,887
10	(506) Miscellaneous Steam Power Expenses	21,643,764	25,563,301
11	(507) Rents		
12	(509) Allowances	14,757,443	9,437,260
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	1,005,676,432	963,227,104
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,081,404	1,930,908
16	(511) Maintenance of Structures	4,017,547	2,017,648
17	(512) Maintenance of Boiler Plant	11,456,972	10,900,717
18	(513) Maintenance of Electric Plant	3,920,387	3,106,253
19	(514) Maintenance of Miscellaneous Steam Plant	24,954,101	32,336,081
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	46,430,411	50,291,607
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,052,106,843	1,013,518,711
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	1,292,454	1,231,265
25	(518) Fuel	32,072,560	30,323,189
26	(519) Coolants and Water	4,202,627	3,634,057
27	(520) Steam Expenses	10,768,233	10,829,485
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	3,563	8,254
31	(524) Miscellaneous Nuclear Power Expenses	42,571,657	39,128,068
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	90,911,094	85,154,318
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	10,666,664	9,826,499
36	(529) Maintenance of Structures	1,758,489	1,537,159
37	(530) Maintenance of Reactor Plant Equipment	15,750,492	17,510,007
38	(531) Maintenance of Electric Plant	1,881,696	2,650,445
39	(532) Maintenance of Miscellaneous Nuclear Plant	2,904,562	2,619,148
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	32,961,903	34,143,258
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	123,872,997	119,297,576
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 Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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	3,961,518	7,703,260
63	(547) Fuel	1,005,783,068	746,008,168
64	(548) Generation Expenses	7,795,973	5,281,861
65	(549) Miscellaneous Other Power Generation Expenses	8,973,220	7,592,687
66	(550) Rents	145,650	
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,026,659,429	766,585,976
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,092,264	527,851
70	(552) Maintenance of Structures	760,835	88,862
71	(553) Maintenance of Generating and Electric Plant	11,980,541	2,127,618
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	20,411,713	18,830,624
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	34,245,353	21,574,955
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	1,060,904,782	788,160,931
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	921,860,536	885,492,819
77	(556) System Control and Load Dispatching	2,264,532	3,342,542
78	(557) Other Expenses	12,793	40,970
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	924,137,861	888,876,331
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	3,161,022,483	2,809,853,549
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,828,865	1,573,682
84	(561) Load Dispatching	43,872	196,591
85	(561.1) Load Dispatch-Reliability	1,212,048	1,071,319
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	845,090	617,624
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,176,516	1,227,897
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	636,145	508,073
90	(561.6) Transmission Service Studies	-718	105,598
91	(561.7) Generation Interconnection Studies	842,803	560,792
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	271,886	116,785
94	(563) Overhead Lines Expenses	71,660	36,856
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	7,561,801	15,710,347
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	17,489,968	21,725,564
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,330,764	
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	71,151	43,846
104	(569.2) Maintenance of Computer Software	256,180	137,395
105	(569.3) Maintenance of Communication Equipment	55,735	49,163
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	8,615,169	4,565,315
108	(571) Maintenance of Overhead Lines	6,931,513	7,040,485
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	2,878,250	2,467,252
111	TOTAL Maintenance (Total of lines 101 thru 110)	20,138,762	14,303,456
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	37,628,730	36,029,020

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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	21,206,569	10,352,589
135	(581) Load Dispatching	4,495,958	4,018,262
136	(582) Station Expenses	60,925	60,454
137	(583) Overhead Line Expenses	5,339,867	5,497,932
138	(584) Underground Line Expenses	2,250,861	3,266,204
139	(585) Street Lighting and Signal System Expenses	5,151,091	4,513,562
140	(586) Meter Expenses	8,862,762	9,031,904
141	(587) Customer Installations Expenses	1,391,200	983,562
142	(588) Miscellaneous Expenses	22,181,469	39,163,804
143	(589) Rents	645,555	573,150
144	TOTAL Operation (Enter Total of lines 134 thru 143)	71,586,257	77,461,423
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,506,866	2,523,003
147	(591) Maintenance of Structures	41,759	13,567
148	(592) Maintenance of Station Equipment	4,884,509	3,483,217
149	(593) Maintenance of Overhead Lines	29,817,899	30,541,293
150	(594) Maintenance of Underground Lines	8,086,742	8,882,118
151	(595) Maintenance of Line Transformers	80,612	417,439
152	(596) Maintenance of Street Lighting and Signal Systems	10,324	
153	(597) Maintenance of Meters	884,396	470,773
154	(598) Maintenance of Miscellaneous Distribution Plant	25,461,009	21,405,981
155	TOTAL Maintenance (Total of lines 146 thru 154)	71,774,116	67,737,391
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	143,360,373	145,198,814
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,446,902	1,349,756
160	(902) Meter Reading Expenses	2,813,895	2,792,307
161	(903) Customer Records and Collection Expenses	29,315,659	28,000,223
162	(904) Uncollectible Accounts	13,548,619	14,312,525
163	(905) Miscellaneous Customer Accounts Expenses	1,818,192	4,594,186
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	49,943,267	51,048,997

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	20,333	851,920
168	(908) Customer Assistance Expenses	63,648,779	63,229,204
169	(909) Informational and Instructional Expenses	7,682,131	8,025,594
170	(910) Miscellaneous Customer Service and Informational Expenses	142,758	191,013
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	71,494,001	72,297,731
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,570,920	1,690,130
176	(913) Advertising Expenses	160,480	
177	(916) Miscellaneous Sales Expenses	43,213	273,910
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,774,613	1,964,040
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	59,234,000	57,011,640
182	(921) Office Supplies and Expenses	26,564,567	31,319,666
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	35,046,074	34,341,216
185	(924) Property Insurance	75,934,878	56,253,594
186	(925) Injuries and Damages	8,882,337	13,570,940
187	(926) Employee Pensions and Benefits	48,155,205	57,607,185
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	381,186	290,638
190	(929) (Less) Duplicate Charges-Cr.	1,513,272	924,167
191	(930.1) General Advertising Expenses	2,089,820	550,155
192	(930.2) Miscellaneous General Expenses	1,803,238	9,679,913
193	(931) Rents	8,565,952	9,988,759
194	TOTAL Operation (Enter Total of lines 181 thru 193)	265,143,985	269,689,539
195	Maintenance		
196	(935) Maintenance of General Plant	-9,046,307	23,279,541
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	256,097,678	292,969,080
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,721,321,145	3,409,361,231

Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4

FOOTNOTE DATA

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PURCHASED POWER:					
2	SOUTHEASTERN POWER ADM	OS	FERC NO. 65	N/A	N/A	N/A
3	GLADES ELECTRIC COOPERATIVE INC.	OS	*	N/A	N/A	N/A
4	AUBURNDALE POWER PARTNERS (1)	OS	COG	134	155	141
5	AUBURNDALE POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
6	CARGILL FERTILIZER (1)	OS	COG	N/A	N/A	N/A
7	CARGILL FERTILIZER (1)	AD	COG	N/A	N/A	N/A
8	CITRUS WORLD (1)	OS	COG	N/A	N/A	N/A
9	CITRUS WORLD (1)	AD	COG	N/A	N/A	N/A
10	LAKE COUNTY (1)	OS	COG	10	13	10
11	LAKE COUNTY (1)	AD	COG	N/A	N/A	N/A
12	LAKE COGEN LIMITED (1)	OS	COG	114	122	103
13	LAKE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
14	DADE COUNTY (1)	OS	COG	38	53	30
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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
14,078				595,038		595,038	2
42				5,546		5,546	3
632,361			41,066,276	28,631,788		69,698,064	4
					-41,405	-41,405	5
			833	19,086		19,919	6
					71,872	71,872	7
21				1,045		1,045	8
-1					-59	-59	9
85,107			6,819,210	2,405,201		9,224,411	10
					-1,358	-1,358	11
476,697			35,124,723	26,222,881		61,347,604	12
					-253,166	-253,166	13
317,732			12,866,973	16,277,315		29,144,288	14
10,167,715			383,666,993	536,797,790	-171,360	920,293,423	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	DADE COUNTY (1)	AD	COG	N/A	N/A	N/A
2	ORANGE COGEN LIMITED (1)	OS	COG	76	106	79
3	ORANGE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
4	ORLANDO COGEN LIMITED (1)	OS	COG	71	94	90
5	ORLANDO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
6	PASCO COGEN LIMITED (1)	OS	COG	98	119	89
7	PASCO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
8	PASCO COUNTY (1)	OS	COG	22	29	24
9	PASCO COUNTY (1)	AD	COG	N/A	N/A	N/A
10	PCS PHOSPHATE (1)	OS	COG	N/A	N/A	N/A
11	PCS PHOSPHATE (1)	AD	COG	N/A	N/A	N/A
12	PINELLAS COUNTY (1)	OS	COG	43	42	18
13	PINELLAS COUNTY (1)	AD	COG	N/A	N/A	N/A
14	POLK POWER PARTNERS (1)	OS	COG	108	126	108
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
					-218,054	-218,054	1
341,262			29,925,053	14,911,862		44,836,915	2
					632,621	632,621	3
490,838			19,810,547	25,340,374		45,150,921	4
82					-17,909	-17,909	5
421,943			41,783,508	17,199,019		58,982,527	6
					35,419	35,419	7
187,747			12,301,320	5,331,217		17,632,537	8
					-2,818	-2,818	9
1,003				74,211		74,211	10
-97					-5,373	-5,373	11
202,972			13,526,070	5,675,687		19,201,757	12
					-6,158	-6,158	13
416,357			50,810,743	15,645,648		66,456,391	14
10,167,715			383,666,993	536,797,790	-171,360	920,293,423	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	POLK POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
2	RIDGE GENERATING STATION (1)	OS	COG	32	39	18
3	RIDGE GENERATING STATION (1)	AD	COG	N/A	N/A	N/A
4	SI GROUP ENERGY	OS	COG	N/A	N/A	N/A
5	SI GROUP ENERGY	AD	COG	N/A	N/A	N/A
6	INTERCHANGE POWER:					
7	CHATTAHOOCHEE, CITY OF	OS				
8	CHATTAHOOCHEE, CITY OF	AD				
9	COBB ELECTRIC MEMBERSHIP CORP.	OS				
10	CAROLINA PWR. & LIGHT CO.	OS	FERC NO. 5			
11	CALPINE ENERGY SVCS., L.P.	OS	FERC NO. 170			
12	CALPINE ENERGY SVCS., L.P.	AD	FERC NO. 170			
13	CARGILL-ALLIANT, LLC	OS				
14	CENTRAL POWER & LIME	AD				
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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)	
					-81,178	-81,178	1
167,813			8,767,279	7,991,079		16,758,358	2
					-50,024	-50,024	3
21,897				1,552,272		1,552,272	4
					-15,245	-15,245	5
							6
			141,936			141,936	7
					8,468	8,468	8
312,831				24,817,663		24,817,663	9
				7,392		7,392	10
107,403				7,756,627		7,756,627	11
					-1,500	-1,500	12
222,882			2,500,000	19,278,833		21,778,833	13
					-481,846	-481,846	14
10,167,715			383,666,993	536,797,790	-171,360	920,293,423	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	CONSTELLATION ENERGY	OS				
2	DUKE ENERGY TRADING	OS				
3	FLORIDA POWER & LIGHT CO.	OS	FERC NO. 81			
4	FLORIDA POWER & LIGHT CO.	AD	FERC NO. 81			
5	FLORIDA MUNICIPAL POWER AGENCY	OS				
6	GEORGIA POWER	OS				
7	GEORGIA TRANSMISSION CORP	OS				
8	HOMESTEAD, CITY OF	OS	FERC NO. 82			
9	JACKSONVILLE ELECTRIC AUTHORITY	OS	FERC NO. 91			
10	JACKSONVILLE ELECTRIC AUTHORITY	AD	FERC NO. 91			
11	LAKELAND, CITY OF	OS	FERC NO. 92			
12	NEW HOPE POWER PARTNERSHIP	OS				
13	NEW SMYRNA BEACH, CITY OF	OS	FERC NO. 104			
14	OGLETHORPE POWER CORP	OS	FERC NO. 139			
	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	12/31/2008	End of 2008/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)	
103,687				7,004,854		7,004,854	1
248				134,511		134,511	2
42,084				3,354,644		3,354,644	3
					22	22	4
							5
							6
				114,124		114,124	7
							8
				2,239,138		2,239,138	9
					-4,899	-4,899	10
							11
769				65,222		65,222	12
					-106,099	-106,099	13
							14
10,167,715			383,666,993	536,797,790	-171,360	920,293,423	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86			
2	PJM INTERCONNECTION, LLC	OS				
3	PJM INTERCONNECTION, LLC	AD				
4	RAINBOW ENERGY MARKETING CORP	OS				
5	REEDY CREEK UTILITIES	OS	FERC NO. 119			
6	RELIANT ENERGY SERVICES INC.	OS	FERC NO. 167			
7	RELIANT ENERGY FLORIDA	OS				
8	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128			
9	SHADY HILLS POWER COMPANY	OS				
10	SHADY HILLS POWER COMPANY	AD				
11	SOUTHERN COMPANY SERVICES INC.	OS	FERC NO. 111			
12	SOUTHERN COMPANY SERVICES INC.	AD	FERC NO. 70			
13	SOUTH CAROLINA ELECTRIC & GAS CO	OS				
14	TALLAHASSEE, CITY OF	OS	FERC NO. 122			
	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	12/31/2008	End of 2008/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)	
18,813				1,921,694		1,921,694	1
22,337				1,045,324		1,045,324	2
					17,160	17,160	3
3,077				190,257		190,257	4
29,610			1,000,000	2,702,637		3,702,637	5
3,710				328,246		328,246	6
211,117			15,006,772	24,742,777		39,749,549	7
103,596				8,815,863		8,815,863	8
1,165,476			26,231,786	136,934,674		163,166,460	9
					-312,200	-312,200	10
3,508,669			58,066,760	90,881,364		148,948,124	11
					1,303,578	1,303,578	12
400				52,000		52,000	13
130				234,435	-617,600	-383,165	14
10,167,715			383,666,993	536,797,790	-171,360	920,293,423	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	THE ENERGY AUTHORITY	OS	FERC NO. 175			
2	TAMPA ELECTRIC CO.	OS	FERC NO. 80			
3	TAMPA ELECTRIC CO.	AD				
4	TENNESSEE VALLEY AUTHORITY	OS				
5	CONOCO PHILLIPS	OS				
6	CINCINATTI GAS & ELECTRIC	OS				
7	INADVERTENT INTERCHANGE (NET)	OS				
8	MUNICIPAL ELECT AUTHORTITY OF GA	OS				
9	MERRILL LYNCH	OS				
10	WILLIAMS POWER COMPANY, INC	OS				
11	WESTAR ENERGY	OS				
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	12/31/2008	End of 2008/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
159,878				13,259,106		13,259,106	1
372,861			7,917,204	23,017,030		30,934,234	2
					-23,609	-23,609	3
							4
100				9,500		9,500	5
							6
183							7
				10,606		10,606	8
							9
							10
							11
							12
							13
							14
10,167,715			383,666,993	536,797,790	-171,360	920,293,423	

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 ($41,405).

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

OUT OF PERIOD ADJUSTMENT: CARGILL FERTILIZER - ENERGY $72,705 AND CAPACITY ($833).

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

OUT OF PERIOD ADJUSTMENT: CITRUS WORLD - ENERGY ($59).

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

OUT OF PERIOD ADJUSTMENT: LAKE COUNTY - ENERGY ($1,358).

Schedule Page: 326 Line No.: 13 Column: l

OUT OF PERIOD ADJUSTMENT: LAKE COGEN LIMITED - ENERGY ($253,166).

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

OUT OF PERIOD ADJUSTMENT: DADE COUNTY - ENERGY ($182,998) AND CAPACITY ($35,056).

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

OUT OF PERIOD ADJUSTMENT: ORANGE COGEN LIMITED - ENERGY $450,621 AND CAPACITY 182,000.

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

OUT OF PERIOD ADJUSTMENT: ORLANDO COGEN LIMITED - ENERGY ($17,909).

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

OUT OF PERIOD ADJUSTMENT: PASCO COGEN LIMITED - ENERGY $35,419.

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

OUT OF PERIOD ADJUSTMENT: PASCO COUNTY - ENERGY ($2,818).

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

OUT OF PERIOD ADJUSTMENT: PCS PHOSPHATE - ENERGY ($5,373).

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

OUT OF PERIOD ADJUSTMENT: PINELLAS COUNTY - ENERGY ($6,158).

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

OUT OF PERIOD ADJUSTMENT: POLK POWER PARTNERS - ENERGY ($81,178).

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

OUT OF PERIOD ADJUSTMENT: RIDGE GENERATING STATION - ENERGY $4,703 AND CAPACITY ($54,727).

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

OUT OF PERIOD ADJUSTMENT: SI GROUP ENERGY - ENERGY ($15,245).

Schedule Page: 326.2 Line No.: 8 Column: a

OUT-OF-PERIOD ADJUSTMENT - Capacity - CITY OF CHATTAHOOCHEE - $8468.

Schedule Page: 326.2 Line No.: 12 Column: a

OUT OF PERIOD ADJUSTMENT - CALPINE ENERGY SVCS., L.P. - ($1,500)

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

OUT OF PERIOD ADJUSTMENT - Capacity - CENTRAL POWER & LIME - ($481,846).

Schedule Page: 326.3 Line No.: 4 Column: a

OUT OF PERIOD ADJUSTMENT - FLORIDA POWER & LIGHT CO. - $22

Schedule Page: 326.3 Line No.: 10 Column: a

OUT-OF-PERIOD ADJUSTMENT - JACKSONVILLE ELECTRIC AUTHORITY - ($4899)

Schedule Page: 326.4 Line No.: 3 Column: a

OUT-OF-PERIOD ADJUSTMENT - PJM - $17,160

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

OUT OF PERIOD ADJUSTMENT - SHADY HILLS POWER COMPANY - ($312,200)

Schedule Page: 326.4 Line No.: 12 Column: a

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

OUT-OF-PERIOD ADJUSTMENT - SOUTHERN COUMPANY SERVICES - $1,303,578

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

OUT-OF-PERIOD ADJUSTMENT - TAMPA ELECTRIC - ($23,609)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	CIty of Alachua-Gainesville	Progress Energy Florida	City of Alachua	LFP
2	City of Bartow	Progress Energy FLorida	City of Bartow	FNO
3	Calpine Energy Services	Various	Various	NF
4	Cargill Power Markets, LLC.	Various	Various	NF
5	Cobb Electric Membership	Various	Various	NF
6	Conoco, Inc.	Various	Various	NF
7	Duke Energy Trading & Mkting	Various	Various	NF
8	Eagle Energy Partners	Various	Various	NF
9	Florida Municipal Power Authorty	Various	Various	NF
10	Florida Power & Light Co.	Various	Various	NF
11	Fortis Energy Marketing Trading	Various	Various	NF
12	Gainesville Regional Utilities	Progress Energy Florida	Gainesville Regional	LFP
13	Georgia Power Company	Progress Energy FLorida	Georgia Power Co.	OLF
14	City of Homestead	Progress Energy Florida	City of Homestead	LFP
15	City of Homestead	Progress Energy Florida	City of Homestead	NF
16	Kissimmee Utility Auth	Progress Energy Florida	Kissimmee Utility Auth	LFP
17	Lakeland Utilites	Various	Various	NF
18	City of Mt. Dora	Progress Energy Florida	City of Mt. Dora	FNO
19	Utilities Comm of New Smyrna Beach	Progress Energy Florida	Utilites Comm of New Smyrna Beach	LFP
20	Utilities Comm of New Smyrna Beach	Various	Various	NF
21	Oglethorpe Power Corp	Various	Various	NF
22	Orange Cogen LP	Orange Cogen LP	Tampa Electric Company	LFP
23	Orlando Utilities Commission	Progress Energy Florida	Orlando Utilities Commission	LFP
24	Orlando Utilities Commission	Various	Various	NF
25	City of Quincy	Progress Energy Florida	City of Quincy	FNO
26	Rainbow Energy Marketing Corp.	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	Progress Energy Florida	Seminole Electric Coop	SFP
31	Seminole Electric Coop	Various	Various	NF
32	Southern Company of Florida	Various	Various	NF
33	City of Tallahassee	Progress Energy Floirda	City of Tallahassee	LFP
34	City of Tallahassee	City of Tallahassee	City of Tallahassee	LFP
	TOTAL			

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		5,493	1
T6/136	Various	City of Bartow		662	656	2
T6/106	Various	Various		17,694	17,320	3
T6/230C	Various	Various		47,875	46,870	4
T6/114	Various	Various				5
T6/232C	Various	Various				6
T6/202C	Various	Various		11,787	11,547	7
T6/257C	Various	Various		2,841	2,783	8
T6/31	Various	Various	19	383	380	9
T6/7C	Various	Various		219	215	10
T6/285C	Various	Various		3,827	3,749	11
T6/73	Crystal River Sub	Gainesville Regional	12	104,726	99,233	12
FERC No. 105	Intercession City Sb	Ga Power Company	146			13
T6/130	Various	FL Power & Light	30	204,741	200,501	14
T6/52	Various	FL Power & Light		8,223	8,055	15
T6/74	Crystal River Sub	Kissimmee Utility	6	47,436	47,436	16
T6/56	Various	Various		1,437	1,408	17
T6/133	Various	City of Mt. Dora		222	220	18
T6/75	Crystal River sub	New Smyrna Beach	5	39,716	39,716	19
T6/12	Various	Various		1,536	1,518	20
T6/187C	Various	Various		316	293	21
T6/77	Orange Sub	Tampa Electric Co	23	75,803	75,803	22
T6/76	Crystal River Sub	Orlando Utilities Cm	13	112,883	112,883	23
T6/10	Various	Various		4,126	4,039	24
T6/137	Various	City of Quincy		247	245	25
T6/35C	Various	Various		16,609	16,328	26
T6/14	Various	Various		8,754	8,569	27
T6/92	Hudson Sub	FL Power & Light				28
T6/3	Various	Various		4,189	4,101	29
T6/24	Progress Energy FL	Seminole Elec Coop	14			30
T6/23	Various	Various		9,712	9,499	31
T6/29C	Various	Various				32
T6/96	Progress Energy FL	City of Tallahassee	11	102,257	100,140	33
T6/97	Jackson Bluff Sub	City of Tallahassee	11	17,675	17,304	34
			292	**2,470,895**	**2,417,412**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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.
10,773			10,773	1
1,184,780			1,184,780	2
56,516			56,516	3
205,674			205,674	4
19,888			19,888	5
				6
130,284			130,284	7
9,297			9,297	8
2,041			2,041	9
696			696	10
17,384			17,384	11
194,588			194,588	12
848,871			848,871	13
572,175			572,175	14
50,309			50,309	15
93,347			93,347	16
5,383			5,383	17
394,278			394,278	18
79,092			79,092	19
4,758			4,758	20
6,202			6,202	21
422,093			422,093	22
221,492			221,492	23
31,785			31,785	24
412,591			412,591	25
-16,257			-16,257	26
21,614			21,614	27
				28
24,192			24,192	29
219,394			219,394	30
19,952			19,952	31
876			876	32
321,084			321,084	33
99,219			99,219	34
43,622,655	**0**	**0**	**43,622,655**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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 Tallahassee	Various	Various	NF
2	Tampa Electric Company	Progress Enegy Florida	Tampa Electric Company	SFP
3	Tampa Electric Company	Various	Various	NF
4	Tampa Electric Company	Tampa Electric Company	Cities of Ft. Meade & Wachula	FNO
5	The Energy Authority	Gainesville Regional Utilities	Gainesville Regional Utililites	LFP
6	The Energy Authority	Various	Various	SFP
7	The Energy Authority	Various	Various	NF
8	City of Williston	Progress Energy Florida	City of Williston	FNO
9	City of Winter Park	Progress Energy Florida	City of Winter Park	FNO
10	City of Homestead	Progress Energy Florida	City of Homestead	SFP
11	Florida Municipal Power Auth-OS	Various	Various	OS
12	Reedy Creek-OS	Various	Various	OS
13	Seminole Electric Cooperative Inc.	Various	Various	OS
14	Southeastern Poer Admin-OS	Various	Various	OS
15	Constellation Power Source	Various	Various	NF
16	Alabama Electric Coop	Various	Various	OS
17	City of New Symrna	Various	Various	NF
18	Pa-NJ-Maryland Int (PJM)	Various	Various	NF
19	Tennessee Valley Authority	Various	Various	NF
20	Carolina Power & Light	Various	Various	NF
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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.
T6/19	Various	Various		673	659	1
T6/25	Progress Enegy FL	Tampa Electric Co.		880,651	858,537	2
T6/160C	Various	Various		23,581	22,922	3
T6/98	Tampa Electric Co	Ft. Meade & Wachula				4
T6/116	Archer Sub	Gainesville Regional	1	250,965	250,965	5
T6/62	Various	Various		47,988	46,987	6
T6/68C	Various	Various		185,900	182,285	7
T6/125	Various	City of Winter Park		76	75	8
T6/124	Various	City of Winter Park		939	933	9
T6/53	Various	City of Homestead		227	222	10
T6/31	Various	Various				11
T6	Various	Various				12
T6	Various	Various				13
T6	Various	Various		233,999	217,523	14
T8	Various	Various				15
T6	Various	Various				16
T6	Various	Various				17
T6	Various	Various				18
T6/70	Various	Various				19
T8	Various	Various				20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			292	**2,470,895**	**2,417,412**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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.
560			560	1
5,072,995			5,072,995	2
59,285			59,285	3
275,045			275,045	4
874,706			874,706	5
448,318			448,318	6
200,763			200,763	7
136,502			136,502	8
1,679,748			1,679,748	9
2,195			2,195	10
4,352,207			4,352,207	11
1,853,811			1,853,811	12
22,612,995			22,612,995	13
306,573			306,573	14
2,115			2,115	15
1,220			1,220	16
157			157	17
59,618			59,618	18
15,848			15,848	19
3,623			3,623	20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
43,622,655	**0**	**0**	**43,622,655**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	3,696,646
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	Inventory Adjustment	2,134,398
7	Stores Burden Adjustment	-269,307
8	Florida Sales Tax Audit	-4,934,848
9	Treasury Fees	470,236
10	Service Company Allocations	682,304
11	Accounting Adjustments	23,809
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		
42		
43		
44		
45		
46	TOTAL	1,803,238

Schedule Page: 335 Line No.: 8 Column: b

Reversal of a sales tax audit reserve, related to sales of electricity, based on a revised audit assessment by the Florida Department of Revenue.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			2,957,229		2,957,229
2	Steam Production Plant	52,590,469	310,657			52,901,126
3	Nuclear Production Plant	18,746,335	1,657			18,747,992
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	64,165,854				64,165,854
7	Transmission Plant	31,442,612				31,442,612
8	Distribution Plant	119,683,122				119,683,122
9	Regional Transmission and Market Operation					
10	General Plant	14,459,370	42,658	151,850		14,653,878
11	Common Plant-Electric					
12	TOTAL	301,087,762	354,972	3,109,079		304,551,813

B. Basis for Amortization Charges

Account 404

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission Fee for				
2	Fiscal year 2008.	381,186		381,186	
3					
4					
5					
6					
7					
8					
9					
10					
11					
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					
42					
43					
44					
45					
46	TOTAL	381,186		381,186	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	2008 Nuclear Power Program
5		
6		
7		
8		
9		
10		
11		
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		

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
	461,460	930	461,460		4
					5
					6
					7
					8
					9
					10
					11
					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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	74,310,836		
4	Transmission	13,222,163		
5	Regional Market			
6	Distribution	44,854,903		
7	Customer Accounts	20,057,602		
8	Customer Service and Informational	12,498,238		
9	Sales	862,519		
10	Administrative and General	57,946,053		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	223,752,314		
12	Maintenance			
13	Production	36,452,150		
14	Transmission	5,652,521		
15	Regional Market			
16	Distribution	19,715,365		
17	Administrative and General	21,326		
18	TOTAL Maintenance (Total of lines 13 thru 17)	61,841,362		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	110,762,986		
21	Transmission (Enter Total of lines 4 and 14)	18,874,684		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	64,570,268		
24	Customer Accounts (Transcribe from line 7)	20,057,602		
25	Customer Service and Informational (Transcribe from line 8)	12,498,238		
26	Sales (Transcribe from line 9)	862,519		
27	Administrative and General (Enter Total of lines 10 and 17)	57,967,379		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	285,593,676	6,107,514	291,701,190
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	12/31/2008	End of 2008/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)	285,593,676	6,107,514	291,701,190
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	88,386,660	9,836,389	98,223,049
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	88,386,660	9,836,389	98,223,049
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Exp Undistributed	8,240,158	-8,240,158	
79	Clearing Accounts	7,703,745	-7,703,745	
80	Misc Deferred Debits	4,005,764		4,005,764
81	All Other Accounts	6,243,507		6,243,507
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	26,193,174	-15,943,903	10,249,271
96	TOTAL SALARIES AND WAGES	400,173,510		400,173,510

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	560,238	MWH	11,123			
2	Reactive Supply and Voltage	560,238	MWH	57,748			
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	1,120,476		68,871			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	12,359	3	800	8,665	235	145	3,031	283	
2	February	10,206	28	800	7,045	186	145	2,547	283	
3	March	8,355	16	1700	5,934	147	145	1,846	283	
4	Total for Quarter 1	30,920			21,644	568	435	7,424	849	
5	April	9,140	4	1700	6,553	169	145	1,990	283	
6	May	11,204	31	1700	7,990	202	145	2,584	283	
7	June	12,043	6	1700	8,587	227	145	2,901	183	
8	Total for Quarter 2	32,387			23,130	598	435	7,475	749	
9	July	12,160	21	1600	8,751	239	145	2,842	183	
10	August	12,190	7	1700	8,822	239	145	2,801	183	
11	September	11,605	8	1700	8,264	229	145	2,684	283	
12	Total for Quarter 3	35,955			25,837	707	435	8,327	649	
13	October	10,015	12	1600	7,207	179	145	2,201	283	
14	November	9,462	20	800	6,436	181	144	2,418	283	
15	December	10,165	3	800	6,958	194	144	2,586	283	
16	Total for Quarter 4	29,642			20,601	554	433	7,205	849	
17	Total Year to Date/Year	128,904			91,212	2,427	1,738	30,431	3,096	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	18,408,505
4	Nuclear	6,424,713
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	12,761,582
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	37,594,800
10	Purchases	10,167,715
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	2,470,895
17	Delivered	2,417,412
18	Net Transmission for Other (Line 16 minus line 17)	53,483
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	47,815,998

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	38,555,709
23	Requirements Sales for Resale (See instruction 4, page 311.)	6,619,497
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	157,856
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	143,530
27	Total Energy Losses	2,339,406
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	47,815,998

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	3,685,296	48,204	10,153	3	800
30	February	3,276,872	25,783	8,223	28	800
31	March	3,533,437	22,526	6,794	16	1700
32	April	3,817,544	4,249	7,619	4	1700
33	May	4,423,524	3,638	9,298	31	1700
34	June	4,633,463	5,332	9,898	6	1700
35	July	4,726,116	2,879	10,012	21	1600
36	August	4,732,683	2,357	10,036	7	1700
37	September	4,578,715	3,971	9,501	8	1700
38	October	3,783,901	3,725	8,059	12	1600
39	November	3,294,475	16,910	7,446	20	800
40	December	3,329,972	18,282	8,064	3	800
41	TOTAL	47,815,998	157,856			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	18,408,505
4	Nuclear	6,424,713
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	12,761,582
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	37,594,800
10	Purchases	10,167,715
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	2,470,895
17	Delivered	2,417,412
18	Net Transmission for Other (Line 16 minus line 17)	53,483
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	47,815,998

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	38,555,709
23	Requirements Sales for Resale (See instruction 4, page 311.)	6,619,497
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	157,856
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	143,530
27	Total Energy Losses	2,339,406
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	47,815,998

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	3,685,296	48,204	10,153	3	800
30	February	3,276,872	25,783	8,223	28	800
31	March	3,533,437	22,526	6,794	16	1700
32	April	3,817,544	4,249	7,619	4	1700
33	May	4,423,524	3,638	9,298	31	1700
34	June	4,633,463	5,332	9,898	6	1700
35	July	4,726,116	2,879	10,012	21	1600
36	August	4,732,683	2,357	10,036	7	1700
37	September	4,578,715	3,971	9,501	8	1700
38	October	3,783,901	3,725	8,059	12	1600
39	November	3,294,475	16,910	7,446	20	800
40	December	3,329,972	18,282	8,064	3	800
41	TOTAL	47,815,998	157,856			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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)	1025			433		
7	Plant Hours Connected to Load	13345			18067		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1038			440		
10	When Limited by Condenser Water	1011			426		
11	Average Number of Employees	67			41		
12	Net Generation, Exclusive of Plant Use - KWh	2457705000			1344444000		
13	Cost of Plant: Land and Land Rights	2685608			1746939		
14	Structures and Improvements	37856488			19639763		
15	Equipment Costs	255963250			126623161		
16	Asset Retirement Costs	0			0		
17	Total Cost	296505346			148009863		
18	Cost per KW of Installed Capacity (line 17/5) Including	266.5456			299.3969		
19	Production Expenses: Oper, Supv, & Engr	846318			638236		
20	Fuel	240324479			140609782		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	261746			250205		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2383			1008		
26	Misc Steam (or Nuclear) Power Expenses	6356938			3474438		
27	Rents	0			0		
28	Allowances	2312856			963863		
29	Maintenance Supervision and Engineering	933343			766967		
30	Maintenance of Structures	855722			162959		
31	Maintenance of Boiler (or reactor) Plant	2560320			519437		
32	Maintenance of Electric Plant	1072967			120537		
33	Maintenance of Misc Steam (or Nuclear) Plant	4508001			2820142		
34	Total Production Expenses	260035073			150327574		
35	Expenses per Net KWh	0.1058			0.1118		
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	2740085	8489495	0	1494593	5114552	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	157471	1031	0	155984	1031	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	60.288	10.078	0.000	61.233	10.074	0.000
41	Average Cost of Fuel per Unit Burned	56.442	10.078	0.000	58.513	10.074	0.000
42	Average Cost of Fuel Burned per Million BTU	8.534	9.776	0.000	8.931	9.770	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.107	0.000	0.000	0.104	0.000
44	Average BTU per KWh Net Generation	0.000	10918.000	0.000	0.000	10693.000	0.000

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Crystal River South* (d)			Plant Name: *Crystal River North* (e)			Plant Name: *Crystal River* (f)			Line No.
Steam			Steam			Nuclear			1
Conventional			Conventional			Conventional			2
1966			1982			1977			3
1969			1984			1977			4
964.35			1478.52			890.46			5
873			1453			797			6
15395			15668			8209			7
0			0			0			8
876			1464			805			9
869			1442			789			10
162			242			563			11
4985966000			9274559000			6424712000			12
2122029			0			-365041			13
75638226			167707816			233920024			14
364708504			797130945			597474807			15
2563413			0			18697977			16
445032172			964838761			849727767			17
461.4841			652.5707			954.2571			18
2350649			3368690			1292454			19
189738303			337736593			32072560			20
0			0			4202627			21
2975138			4930903			10768233			22
0			0			0			23
0			0			0			24
13229			16488			3563			25
3727005			6172548			42571657			26
0			0			0			27
7394365			4043161			0			28
187310			175370			10666664			29
608737			2246602			1758489			30
3237813			4874279			15750492			31
1178863			1004804			1881696			32
9830120			6677326			2904562			33
221241532			371246764			123872997			34
0.0444			0.0400			0.0193			35
Oil	Coal		Oil	Coal		Oil	Nuclear		36
BBL	Tons		BBL	Tons		BBL	MMBTU		37
14330	2070856	0	54882	3735029	0	339	65906070	0	38
138649	12142	0	138595	11923	0	137870	0	0	39
114.716	94.730	0.000	107.322	87.419	0.000	0.000	0.000	0.000	40
101.553	94.078	0.000	101.867	86.090	0.000	0.000	0.487	0.000	41
17.439	3.874	0.000	17.500	3.610	0.000	0.000	0.487	0.000	42
0.000	0.039	0.000	0.000	0.035	0.000	0.000	0.005	0.000	43
0.000	10086.000	0.000	0.000	9603.000	0.000	0.000	10259.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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

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

Line No.	Item (a)	Plant Name: *Suwannee* (b)			Plant Name: *Bayboro* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1953			1973		
4	Year Last Unit was Installed	1956			1973		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	147.00			226.80		
6	Net Peak Demand on Plant - MW (60 minutes)	132			203		
7	Plant Hours Connected to Load	10591			500		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	133			231		
10	When Limited by Condenser Water	131			174		
11	Average Number of Employees	38			5		
12	Net Generation, Exclusive of Plant Use - KWh	345831000			18969000		
13	Cost of Plant: Land and Land Rights	22059			1576410		
14	Structures and Improvements	5040305			1692332		
15	Equipment Costs	31346266			23309296		
16	Asset Retirement Costs	0			0		
17	Total Cost	36408630			26578038		
18	Cost per KW of Installed Capacity (line 17/5) Including	247.6778			117.1871		
19	Production Expenses: Oper, Supv, & Engr	717516			124504		
20	Fuel	44289459			3589291		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	203092			180008		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1008			0		
26	Misc Steam (or Nuclear) Power Expenses	1894262			332322		
27	Rents	0			0		
28	Allowances	43198			0		
29	Maintenance Supervision and Engineering	18414			194		
30	Maintenance of Structures	143527			14005		
31	Maintenance of Boiler (or reactor) Plant	265123			0		
32	Maintenance of Electric Plant	543216			110094		
33	Maintenance of Misc Steam (or Nuclear) Plant	1118512			707573		
34	Total Production Expenses	49237327			5057991		
35	Expenses per Net KWh	0.1424			0.2666		
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	61774	3776006	0	44976	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	155071	1029	0	139181	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	97.332	10.507	0.000	96.140	0.000	0.000
41	Average Cost of Fuel per Unit Burned	73.226	10.507	0.000	79.246	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	11.243	10.214	0.000	13.557	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.153	0.000	0.000	0.188	0.000	0.000
44	Average BTU per KWh Net Generation	13570.000	0.000	0.000	13860.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Debary* (d)			Plant Name: *Intercession City* (e)			Plant Name: *Suwannee* (f)			Line No.
		Gas Turbine			Gas Turbine			Gas Turbine	1
		Conventional			Conventional			Conventional	2
		1975			1974			1980	3
		1992			1992			1980	4
		861.22			1310.20			183.60	5
		715			1087			177	6
		2592			10773			2281	7
		0			0			0	8
		785			1186			200	9
		645			987			153	10
		19			38			2	11
		141374000			665125000			93734000	12
		3140049			746305			0	13
		9672119			15845240			1471200	14
		145423276			240472092			29417578	15
		0			0			0	16
		158235444			257063637			30888778	17
		183.7341			196.2018			168.2395	18
		980391			558396			141059	19
		20640310			99618420			13749801	20
		0			0			0	21
		157029			651064			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		1059418			1826725			259850	26
		0			0			0	27
		0			0			0	28
		0			295511			0	29
		43981			30526			0	30
		0			0			0	31
		131554			2025833			159436	32
		1113854			3183290			573795	33
		24126537			108189765			14883941	34
		0.1707			0.1627			0.1588	35
Oil	Gas		Oil	Gas		Oil	Gas		36
BBL	MCF		BBL	MCF		BBL	MCF		37
54206	1571940	0	83431	8023415	0	20010	1185793	0	38
138169	1034	0	137373	1021	0	138377	1026	0	39
89.068	10.075	0.000	106.722	11.371	0.000	101.754	9.999	0.000	40
86.888	10.075	0.000	97.756	11.371	0.000	91.843	9.999	0.000	41
14.973	9.748	0.000	16.943	11.134	0.000	15.803	9.742	0.000	42
0.205	0.000	0.000	0.221	0.000	0.000	0.225	0.000	0.000	43
13717.000	0.000	0.000	13044.000	0.000	0.000	14226.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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

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

Line No.	Item (a)	Plant Name: *Bartow* (b)			Plant Name: *Turner* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Gas Turbine			Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1972			1970
4	Year Last Unit was Installed			1972			1974
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			222.80			180.98
6	Net Peak Demand on Plant - MW (60 minutes)			203			174
7	Plant Hours Connected to Load			832			328
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			228			199
10	When Limited by Condenser Water			177			149
11	Average Number of Employees			4			0
12	Net Generation, Exclusive of Plant Use - KWh			37055000			17588000
13	Cost of Plant: Land and Land Rights			0			824781
14	Structures and Improvements			1074388			1431173
15	Equipment Costs			25651101			24196281
16	Asset Retirement Costs			0			0
17	Total Cost			26725489			26452235
18	Cost per KW of Installed Capacity (line 17/5) Including			119.9528			146.1611
19	Production Expenses: Oper, Supv, & Engr			425506			135039
20	Fuel			4410546			4123845
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			10885			33685
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			303355			247432
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			3772			34666
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			43125			45189
33	Maintenance of Misc Steam (or Nuclear) Plant			325621			2246524
34	Total Production Expenses			5522810			6866380
35	Expenses per Net KWh			0.1490			0.3904
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	14923	464299	0	45	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138985	1031	0	138281	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	116.852	9.914	0.000	104.565	0.000	0.000
41	Average Cost of Fuel per Unit Burned	84.011	9.914	0.000	88.868	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	14.392	9.618	0.000	15.302	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.233	0.000	0.000	0.225	0.000	0.000
44	Average BTU per KWh Net Generation	16222.000	0.000	0.000	14706.000	0.000	0.000

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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: *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
59	121	215	6
691	1342	3169	7
0	0	0	8
69	129	224	9
48	113	205	10
0	3	11	11
16244000	32108000	567834000	12
60423	184271	0	13
405755	754453	10426281	14
9676358	18612885	72778445	15
0	0	0	16
10142536	19551609	83204726	17
150.0819	127.4302	299.1900	18
176837	93199	658950	19
3611609	5320285	41038108	20
0	0	0	21
20029	215820	647640	22
0	0	0	23
0	0	0	24
0	0	0	25
135037	208023	818883	26
0	0	0	27
0	0	145650	28
21243	0	189154	29
1507	11418	97635	30
0	0	0	31
13074	48487	3304347	32
308955	483379	939601	33
4288291	6380611	47839968	34
0.2640	0.1987	0.0842	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Oil	Gas		Oil	Gas		Gas			36
BBL	MCF		BBL	MCF		MCF			37
18628	157244	0	3754	511030	0	4288121	0	0	38
138418	1033	0	137130	1031	0	1025	0	0	39
115.477	10.605	0.000	112.172	10.049	0.000	9.570	0.000	0.000	40
103.886	10.605	0.000	48.876	10.049	0.000	9.570	0.000	0.000	41
17.870	10.271	0.000	8.486	9.749	0.000	9.338	0.000	0.000	42
0.298	0.000	0.000	0.000	0.167	0.000	0.072	0.000	0.000	43
16662.000	0.000	0.000	0.000	17079.000	0.000	7739.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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

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

Line No.	Item (a)	Plant Name: *Rio Pinar* (b)			Plant Name: *Univ. of Florida* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1970			1994		
4	Year Last Unit was Installed	1970			1994		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	19.29			43.00		
6	Net Peak Demand on Plant - MW (60 minutes)	14			47		
7	Plant Hours Connected to Load	12			7419		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	16			47		
10	When Limited by Condenser Water	12			46		
11	Average Number of Employees	0			11		
12	Net Generation, Exclusive of Plant Use - KWh	144000			348994000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	85819			6541136		
15	Equipment Costs	3179655			37633372		
16	Asset Retirement Costs	0			0		
17	Total Cost	3265474			44174508		
18	Cost per KW of Installed Capacity (line 17/5) Including	169.2833			1027.3141		
19	Production Expenses: Oper, Supv, & Engr	16791			437630		
20	Fuel	48809			28470544		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4559			182245		
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	20070			73878		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			321209		
30	Maintenance of Structures	5925			41666		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	5099			351424		
33	Maintenance of Misc Steam (or Nuclear) Plant	17469			2251264		
34	Total Production Expenses	118722			32129860		
35	Expenses per Net KWh	0.8245			0.0921		
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	437	0	0	3381797	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138063	0	0	1030	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	153.439	0.000	0.000	8.394	0.000	0.000
41	Average Cost of Fuel per Unit Burned	92.544	0.000	0.000	8.394	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	15.960	0.000	0.000	8.152	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.281	0.000	0.000	0.081	0.000	0.000
44	Average BTU per KWh Net Generation	17597.000	0.000	0.000	9979.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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.
			1
Gas Turbine			2
Conventional			3
1999			4
2007			5
2265.75	0.00	0.00	6
2058	0	0	7
27408	0	0	8
0	0	0	9
2204	0	0	10
1912	0	0	11
58	0	0	12
10822413000	0	0	13
10012624	0	0	14
123754606	0	0	15
931079916	0	0	16
0	0	0	17
1064847146	0	0	18
469.9756	0.0000	0.0000	19
213216	0	0	20
781161500	0	0	21
0	0	0	22
5693009	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
3706800	0	0	27
0	0	0	28
0	0	0	29
264953	0	0	30
475734	0	0	31
0	0	0	32
5742879	0	0	33
8260388	0	0	34
805518479	0	0	35
0.0744	0.0000	0.0000	36

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Oil	Gas								36
BBL	MCF								37
7813	75593561	0	0	0	0	0	0	0	38
133657	1023	0	0	0	0	0	0	0	39
162.524	10.317	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
65.463	10.317	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
11.661	10.086	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.083	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
7149.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: f

Crystal River plant contains on pressurized water reactor. The nuclear fuel assemblies in the reactor contains enriched uranium. The cost of power generated at the plant is accounted for in accordance with instructions as set forth in the FERC Classification of Accounts. The cost of nuclear fuel is amortized to fuel expense on a unit of production basis.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	2.14		
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	73.50		1
34	CENTRAL FLORIDA	SILVER SPRINGS	230.00	230.00	ST	29.01	5.15	2
35	CENTRAL FLORIDA	SORRENTO	230.00	230.00	CP	14.65		1
36					TOTAL	4,384.97	538.17	83

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
2156 KCM ACSR	2,282,211	20,844,985	23,127,196					2
2335 KCM ACSR	12,767	12,252,818	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		2,034,971	2,034,971					8
2500 KCM CU	258,670	2,163,212	2,421,882					9
								10
								11
1081 KCM ACSR	85,476	3,906,836	3,992,312					12
954 KCM ACSR								13
954 KCM ACSR								14
954 KCM ACSR								15
954 KCM ACSR								16
1590 KCM ACSR	1,321,547	8,930,228	10,251,775					17
1590 KCM ACSR								18
1590 KCM ACSR								19
1590 KCM ACSR	521,102	5,894,309	6,415,411					20
1590 KCM ACSR								21
1590 KCM ACSR		723,363	723,363					22
2335 KCM ACAR	1,237,622	1,387,207	2,624,829					23
1590 KCM ACSR	43,803	1,566,206	1,610,009					24
1590 KCM ACSR								25
1590 KCM ACSR								26
1590 KCM ACSR								27
1590 KCM ACSR	133,007	3,115,556	3,248,563					28
1622 KCM		3,429,434	3,429,434					29
1590 KCM ACSR		100,119	100,119					30
1590 KCM ACSR	1,273,186	11,953,566	13,226,752					31
1590 KCM ACSR	775,227	6,981,750	7,756,977					32
954 KCM ACSR	219,431	8,482,945	8,702,376					33
1590 KCM ACSR	442,027	3,938,777	4,380,804					34
1590 KCM ACSR	1,621,137	10,461,338	12,082,475					35
	80,517,928	805,673,849	886,191,777	71,660	6,931,513		7,003,173	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	12/31/2008	End of 2008/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1					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	4,384.97	538.17	83

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590 KCM ACSR								1
1590 KCM ACSR	1,128,343	7,371,153	8,499,496					2
954 KCM ACSR	1,207,871	4,162,836	5,370,707					3
954 KCM ACSR								4
954 KCM ACSR	626,506	5,813,441	6,439,947					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	828,028	2,817,962	3,645,990					13
1590 KCM ACSR								14
1590 KCM ACSR								15
954 KCM ACSR	233,626	2,861,821	3,095,447					16
954 KCM ACSR								17
1590 KCM ACSR								18
1431 KCM ACSR								19
1590 KCM ACSR								20
954 KCM ACSR	195,181	1,628,711	1,823,892					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	4,202,609	4,266,532					32
954 KCM ACSR								33
954 KCM ACSR								34
1081 KCM ACAR	55,284	3,221,540	3,276,824					35
	80,517,928	805,673,849	886,191,777	71,660	6,931,513		7,003,173	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	12/31/2008	End of 2008/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					WH	16.80		
2					SP	2.90		1
3	TIGER BAY	TECO	230.00	230.00	CP	0.10		1
4					ST	5.86		
5					WH	1.38		
6	HINES ENERGY	FORT MEADE	230.00	230.00	SP	6.45		1
7	HINES ENERGY	BARCOLA	230.00	230.00	SP	3.09		1
8	HINES ENERGY	BARCOLA (2ND CIRCUIT)	230.00	230.00	SP	3.09		1
9	HINES ENERGY	TIGER BAY	230.00	230.00	SP	0.64	3.51	
10	HINES PLANT	HINES	230.00	230.00	SP	1.64		
11	HINES	WEST LAKE WALES	230.00	230.00	SP	20.57		1
12	OLD SUB NORTH	NEW SUB NORTH	230.00	230.00	SP	0.22		1
13	INTERCESSION CITY	LAKE BRYAN 2ND CIRCUIT	230.00	230.00	SP	7.84		1
14	KATHLEEN	WEST LAKELAND	230.00	230.00	WH	14.50		1
15					CP	1.31		
16	KATHLEEN	ZEPHYRHILLS NORTH	230.00	230.00	WH	0.83		1
17					CP	8.70		
18					WP	1.35		
19	LARGO	PASADENA	230.00	230.00	ST		1.61	1
20					SP	13.13		
21	LAKE TARPON	CURLEW	230.00	230.00	ST	4.32		1
22	LAKE TARPON	HIGGINS	230.00	230.00	CP	2.57		1
23					SP	3.02		
24	LAKE TARPON	LARGO	230.00	230.00	SP	14.49		1
25					CP	2.90		
26	LAKE TARPON	SEVEN SPRINGS	230.00	230.00	ST	2.90		1
27	LAKE TARPON	TECO EXIST	230.00	230.00	ST	0.68		1
28					SP	0.81		
29	NORTHEAST	CURLEW	230.00	230.00	ST	16.95	12.78	1
30	NORTHEAST	40TH ST.	230.00	230.00	CP	0.16		1
31					SP	8.16		
32	NORTH LONGWOOD	PIEDMONT	230.00	230.00	SP	0.31	4.04	1
33					WH	6.16		
34	NORTH LONGWOOD	FP&L CO TIE	230.00	230.00	SP	4.04		1
35					WH	2.77		
36					TOTAL	4,384.97	538.17	83

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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)	
1081 KCM ACAR								1
1622 ACSS/TW								2
1590/1081 KCM	359,563	133,977	493,540					3
1081 KCM ACAR								4
1081/954 KCM								5
954 KCM ACSR		2,896,669	2,896,669					6
954 KCM ACSR		1,461,146	1,461,146					7
954 KCM ACSR		1,449,137	1,449,137					8
954 KCM ACSR		1,521,594	1,521,594					9
954 KCM ACSR		1,573,680	1,573,680					10
1622 ACSS/TW	6,148,371	40,163,340	46,311,711					11
2335 KCM ACAR		194,088	194,088					12
1622 ACSS TW		6,053,014	6,053,014					13
1590 KCM ACSR	507,363	3,379,559	3,886,922					14
1590 KCM ACSR								15
1590 KCM ACSR	275,097	3,486,259	3,761,356					16
1590 KCM ACSR								17
1590 KCM ACSR								18
1590 KCM ACSR	152,473	3,061,090	3,213,563					19
1590 KCM ACSR								20
1590 KCM ACSR		955,417	955,417					21
1590 KCM ACSR	15,699	1,499,798	1,515,497					22
1590 KCM ACSR								23
1590 KCM ACSR	412,563	8,586,465	8,999,028					24
1590 KCM ACSR								25
1590 KCM ACSR	189,338	694,404	883,742					26
1590 KCM ACSR		197,855	197,855					27
1590 KCM ACSR								28
1590 KCM ACSR	1,524,958	2,531,962	4,056,920					29
1590 KCA ACSR	288,076	1,390,094	1,678,170					30
1081 KCA ACAR								31
954 KCM ACSR	16,834	1,411,376	1,428,210					32
954 KCM ACSR								33
954 KCM ACSR	207,841	1,301,617	1,509,458					34
954 KCM ACSR								35
	80,517,928	805,673,849	886,191,777	71,660	6,931,513		7,003,173	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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	NORTH LONGWOOD	RIO PINAR	230.00	230.00	SP	0.58	3.94	1
2					CP	0.21		
3					AT	10.91		
4	NEWBERRY	WILCOX	230.00	230.00	SP	19.33		1
5	NORTHEAST	PINELLAS	230.00	230.00	CP	1.90		1
6	PIEDMONT	SORRENTO	230.00	230.00	SP	4.24		1
7					CP	6.45		
8					WH	4.79		
9	PIEDMONT	WOODSMERE	230.00	230.00	WH	6.72		1
10	PORT ST. JOE	GULF POWER	230.00	230.00	ST	33.99		1
11	RIO PINAR	OUC TIE	230.00	230.00	SP	0.52		1
12					AT	2.19		
13	SILVER SPRINGS	DELAND WEST	230.00	230.00	SL	39.93		1
14					SH	0.92		
15					SP	1.57		
16	SUWANNEE RIVER PLANT	FORT WHITE	230.00	230.00	ST	38.08		1
17	SKY LAKE	OUC TIE	230.00	230.00	CP	2.40		1
18					WP	2.22		
19	SUWANNEE	PERRY	230.00	230.00	ST	28.61		1
20	SUWANNEE PEAKERS	SUWANNEE	230.00	230.00	WH	0.63		1
21	SUWANNEE	GEORGIA GPC TIE	230.00	230.00	ST	18.36		1
22	TIGER BAY	FORT MEADE 2	230.00	230.00	SP	0.44	1.78	1
23	ULMERTON	LARGO	230.00	230.00	ST	5.05		1
24	VANDOLAH	SEMINOLE	230.00	230.00	SP	0.03		1
25	VANDOLAH	WHIDDEN	230.00	230.00	SP	14.40		1
26	WINDERMERE	INTERCESSION CITY	230.00	230.00	SP	15.07		1
27					CP	0.14		
28	WINDERMERE	WOODSMERE	230.00	230.00	WH	4.68		1
29					ST	1.82		
30	WEST LAKE WALES	INTERCESSION CITY	230.00	230.00	WH	29.34		1
31					SP	0.79		
32	WEST LAKE WALES	FP&L TIE	230.00	230.00	AT	58.48		1
33	WEST LAKE WALES	TECO TIE	230.00	230.00	AT	2.29		1
34	WINDERMERE	OUC TIE	230.00	230.00	WH	1.31		1
35	WOODSMERE	OUC TIE	230.00	230.00	ST		0.92	1
36					TOTAL	4,384.97	538.17	83

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590 KCM ACSR	420,736	1,828,798	2,249,534					1
954 KCM ACSR								2
954 KCM ACSR								3
1590 KCM ACSR	75,328	5,772,719	5,848,047					4
954 KCM ACSR		4,498	4,498					5
1590 KCM ACSR	574,273	5,252,145	5,826,418					6
1590 KCM ACSR								7
1590 KCM ACSR								8
954 KCM ACSR	15,605	587,317	602,922					9
795 KCM ACSR	71,747	2,336,296	2,408,043					10
954 KCM ACSR	100,034	2,111,864	2,211,898					11
954 KCM ACSR								12
1590 KCM ACSR	54,890	6,798,769	6,853,659					13
1590 KCM ACSR								14
1590 KCM ACSR								15
954 KCM ACSR	199,660	2,362,830	2,562,490					16
954 KCM ACSR	121,530	1,297,008	1,418,538					17
954 KCM ACSR								18
795 KCM ACSR	151,754	1,320,102	1,471,856					19
795 KCM ACSR		8,063	8,063					20
954 KCM ACSR	104,190	1,110,105	1,214,295					21
954 KCM ACSR		779,443	779,443					22
1590 KCM ACSR	601,048	1,780,364	2,381,412					23
954 ACSS TW		824,579	824,579					24
1622 ACSS TW		13,970,582	13,970,582					25
954 KCM ACSR	135,968	7,546,159	7,682,127					26
1622 ACSS/TW								27
1590 KCM ACSR	19,739	1,139,305	1,159,044					28
1590 KCM ACSR								29
954/1081 KCM	364,444	3,295,463	3,659,907					30
1622ACSS TW								31
954 KCM ACSR	595,327	5,463,601	6,058,928					32
954 KCM ACSR	17,342	232,082	249,424					33
954 KCM ACSR		530,178	530,178					34
954 KCM ACSR		4,479	4,479					35
	80,517,928	805,673,849	886,191,777	71,660	6,931,513		7,003,173	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	12/31/2008	End of 2008/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								
2	OTHER TRANS. LINES	OVERHEAD 115 & 69				2,869.24	304.00	
3	OTHER TRANS. LINES	UNDERGROUND 115				47.29		
4								
5	Total Overhead Transmission	Line Expenses				4,365.23	538.17	78
6		(230, 115, 69 Kv)						
7	NEW LINES FOR 2008							
8	CENTRAL FLORIDA	BUSHNELL EAST	230.00	230.00	SP	8.28		1
9	LAKE BRYAN	WINDERMERE	230.00	230.00	SP	9.76		2
10	BARTOW PLANT	NORTHEAST (GENERATION	230.00	230.00	SP	1.53		1
11	NORTHEAST	NORTHEAST (SUB BUS)	230.00	230.00	SP	0.17		1
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					TOTAL	4,384.97	538.17	83

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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)	
								1
	45,540,012	458,693,818	504,233,830					2
	88,132	12,305,496	12,393,628					3
				71,660	6,931,513		7,003,173	4
	75,803,061	788,773,922	864,576,983	71,660	6,931,513		7,003,173	5
								6
								7
1622 ACSS/TW	3,342,578	6,858,152	10,200,730					8
1622 ACSS/TW	1,372,289	7,388,002	8,760,291					9
1590 ACSR		2,146,291	2,146,291					10
1590 ACSR		507,482	507,482					11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	80,517,928	805,673,849	886,191,777	71,660	6,931,513		7,003,173	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	12/31/2008	2008/Q4

FOOTNOTE DATA

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

2008 transmission pole mile statistics have been updated to reflect current and prior year minor additions.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	CEN FLA	CFBE 56-1	8.28	SP	8.00	1	1
2	CF 235	BRONSON	0.19	SP	11.00	1	1
3	LAKE BRYAN	WINDERMERE	9.76	SP	8.00	2	2
4	WINDERMERE	INTER CITY (INSTALLATION)	9.74	SP	8.00	2	2
5	WINDERMERE	INTER CITY (REMOVAL)	-9.93	WP/CP			
6	CFO-46	CFO-47	0.69	CP	13.00	1	1
7	DALLAS	DSX-1/3	0.07	CP	2.00	1	1
8	DLP 66A	LAKE PLACID NORTH	4.37	CP	14.00	2	2
9	CAMP LAKE	GROVELAND	14.64	CP/SP	16.00	2	2
10	CAMP LAKE	GROVELAND (REMOVAL)	-14.64	WP			
11	CAMP LAKE	CLL-42 (INSTALLATION)	2.07	CP/SP	16.00	3	3
12	CAMP LAKE	CLL-42 (REMOVAL)	-3.33	WP			
13	INTERCESSION CITY (ICLB)	LAKE WILSON	6.22	CP	17.00	1	1
14	INTERCESSION CITY (ICLB)	LAKE WILSON (REMOVAL)	-6.22	WP			
15	WLB 20-1/2	WLB-22	0.14	SP	8.00	1	1
16	ZEPHYRHILL NORTH	NEW RIVER	11.45	CP	15.00	1	1
17	LMP-204	LMP-205	0.19	CP	9.00	1	1
18	WOODSMERE	OCOEE (INSTALLATION)	4.96	CP	22.00	1	1
19	WOODSMERE	OCOEE (REMOVAL)	-4.96	WP			
20	LAKE MARION	LMP-8	0.02	CP	23.00	1	1
21	ICLW-3	ICLW-4	0.61	CP	10.00	1	1
22	AA-1	AA-5	0.25	CP	5.00	1	1
23	BCF-212	BUSHNELL EAST	1.85	SP	13.00	1	1
24	BCF-212	BUSHNELL EAST	-1.85	WP			
25	BUSHNELL EAST	BCF-212-1	0.40	CP	13.00	1	1
26	BW-17-29	BW-17-30	0.19	CP	15.00	1	1
27	AF2-95-21-1A	SOUTH POLK	0.11	CP	11.00	1	1
28	AF-162	AF-163	0.13	CP	7.00	1	1
29	BWSX-23-48	HERNANDO AIRPORT	0.96	CP	17.00	1	1
30	BPS-1	BPS-24	1.53	SP	20.00	1	1
31	NNSB-1	NNSB-4	0.17	SP	23.00	1	1
32	MEADOW WOODS EAST	MEADOW WOODS SOUTH	3.97	CP	10.00	1	1
33	NEW RIVER	NRX-5	0.25	CP	32.00	1	1
34	TZ 485-1	TZ 485-19	2.20	CP	15.00	1	1
35	TZ 485-1	TZ 485-19	-1.10	CP			
36	IO 412	SILVER SPRINGS	10.90	SP	14.00	1	1
37	IO 412	SILVER SPRINGS	-10.90	WP			
38							
39							
40							
41							
42							
43							
44	TOTAL		43.38		395.00	35	35

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1622	ACSS/TW	VERTICAL	230	3,342,578	5,117,786	1,740,366		10,200,730	1
954	ACSR	VERTICAL	230		404,960	190,569		595,529	2
1622	ACSS/TW	VERTICAL	230	1,372,289	6,015,654	1,372,348		8,760,291	3
1622	ACCS/TW	VERTICAL	230		1,287,041	1,787,602		3,074,643	4
954	ACSR	VERTICAL	230				-424,213	-424,213	5
1590	ACSR	VERTICAL	230		356,135	313,193	-1,511	667,817	6
795	AAC	VERTICAL	69		10,900	20,294	-5,649	25,545	7
796	ACSR	VERTICAL	69	686,868	2,217,712	809,011		3,713,591	8
795	ACSS/TW	VERTICAL	69	499,555	7,137,134	2,261,049		9,897,738	9
4/0	ACSR	VERTICAL	69				-273,456	-273,456	10
795	AAC	VERTICAL	69		825,986	257,287		1,083,273	11
4/0	ACSR	VERTICAL	69				-18,960	-18,960	12
1272	ACSS/TW	VERTICAL	69		280,754	889,054		1,169,808	13
795	AAC	VERTICAL	69				-456,497	-456,497	14
795	ACSR	VERTICAL	69		79,781	174,827		254,608	15
795	ACSR	VERTICAL	69	3,164,159	550,209	8,098,320		11,812,688	16
795	ACSR	VERTICAL	69		130,809	64,055	-2,558	192,306	17
1272	ACSS/TW	VERTICAL	69		4,530,214	37,919		4,568,133	18
795	AAC	VERTICAL	69				-148,250	-148,250	19
795	AAC	HORIZONTAL	69		39,776	10,480		50,256	20
795	ACSS/TW	VERTICAL	69	617,111	153,367	276,014	-7,531	1,038,961	21
954	ACSS/TW	VERTICAL	69		301,598	84,907		386,505	22
795	ACSR	VERTICAL	69		533,438	456,928		990,366	23
336	ACSR	VERTICAL	69				-79,284	-79,284	24
795	ACSR	VERTICAL	69		285,001	16,465		301,466	25
336	ACSR	VERTICAL	69		146,731	99,818		246,549	26
4/0	ACSR	HORIZONTAL	115		20,695	13,051		33,746	27
954	ACSR	HORIZONTAL	230		148,712	114,992	-7,453	256,251	28
795	ACSR	HORIZONTAL	115	116,139	642,157	304,236		1,062,532	29
1590	ACSR	VERTICAL	230		1,828,435	317,856		2,146,291	30
1590	ACSR	VERTICAL	230		407,606	99,876		507,482	31
795	ACSR	VERTICAL	69	3,318,913	719,094	1,859,013		5,897,020	32
795	ACSR	VERTICAL	69		24,912	27,041		51,953	33
795	ACSR	VERTICAL	69		1,101,680	436,770		1,538,450	34
795	AAC	VERTICAL	69				-70,046	-70,046	35
1272	ACSS/TW	VERTICAL	69	175,822	609,252	3,324,513		4,109,587	36
19	COPPER	VERTICAL	69				323,139	323,139	37
									38
									39
									40
									41
									42
									43
				13,293,434	35,907,529	25,457,854	-1,172,269	73,486,548	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	12/31/2008	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	32ND STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	40TH STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
3	51ST STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
4	ALDERMAN - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
5	ANCLOTE - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
6	BAYBORO - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	BAYVIEW - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	BAYWAY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
9	BELLEAIR - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	BROOKER CREEK - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	BROOKSVILLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	12.00
12	BROOKSVILLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	7.00
13	BROOKSVILLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	13.00
14	BROOKSVILLE ROCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	2.00	
15	BUSHNELL - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	CAMPS SECTION 7 MINE-COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
17	CENTER HILL - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	CENTRAL PLAZA - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
19	CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	CONSOLIDATED ROCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
21	CROSS BAYOU - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	CROSSROADS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	CURLEW - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	DENHAM - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	DISSTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
26	DISSTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
27	DUNEDIN - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	14.00
29	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	240.00	120.00	
30	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
31	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	ELFERS -COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
33	FLORAL CITY - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	FLORA-MAR - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
35	FLORIDA ROCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	66.00	3.00	
36	G.E. PINELLAS - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	GATEWAY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
38	HAMMOCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
39	HAMMOCK - COASTAL FLORDA REGION	DIST - UNATTENDED	67.00	4.00	
40	HERNANDO AIRPORT - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	12.47	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2					1
60	2					2
80	2					3
90	3					4
100	2					5
60	2					6
100	2					7
40	1					8
80	2					9
60	2					10
150	1					11
100	1					12
60	2					13
9	1	1				14
13	1					15
19	2	1				16
13	1	1				17
60	2					18
120	4					19
2	1	1				20
150	3					21
80	2					22
90	3					23
90	3					24
150	1					25
80	2					26
60	3					27
200	1					28
200	1					29
250	1					30
150	3					31
100	2					32
13	1					33
100	2					34
12	2	2				35
29	2					36
90	3					37
20	1					38
19	2					39
33	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	12/31/2008	End of 2008/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	HIGHLANDS - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	HIGGINS PLANT - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
3	KENNETH CITY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
4	LAND-O-LAKES - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
5	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
6	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
7	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	5.00
8	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	MAXIMO - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
10	NEW PORT RICHEY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	NORTHEAST - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	15.00
12	NORTHEAST - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
13	OAKHURST - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	PALM HARBOR - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
15	PALM HARBOR - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	PASADENA - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
17	PASADENA - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
18	PILSBURY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
19	PINELLAS WELL FIELD - COASTAL FLORIDA REGION	DIST - UNATTENDED	66.00	3.00	
20	PORT RICHEY WEST - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
21	SAFETY HARBOR - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
22	SEMINOLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
23	SEMINOLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	SEVEN SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
25	SEVEN SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
26	SIXTEENTH ST. - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
27	STARKEY ROAD - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	TANGERINE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	8.00
29	TARPON SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	
30	TARPON SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
31	TAYLOR AVE. - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	TRI-CITY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
33	TRILBY - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
34	ULMERTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	14.00
35	ULMERTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
36	ULMERTON WEST - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	VINOY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
38	WALSINGHAM - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	ZEPHYRHILLS - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	ZEPHYRHILLS NORTH - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	

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	12/31/2008	End of 2008/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.
80	2					1
						2
60	2					3
30	1					4
200	1					5
200	1					6
200	1					7
100	2					8
150	3					9
60	2					10
400	2					11
100	2					12
90	3					13
250	1					14
60	2					15
250	1					16
80	2					17
100	2					18
5	1	1				19
90	3					20
80	2					21
250	1					22
100	2					23
60	2					24
750	3					25
80	2					26
80	2					27
60	2					28
150	1					29
100	2					30
80	2					31
60	2					32
9	1	1				33
450	2					34
100	2					35
80	2					36
100	2					37
100	2					38
60	2					39
250	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	12/31/2008	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ZEPHYRHILLS NORTH - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2					
3					
4	ALACHUA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	APALACHICOLA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	ARCHER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
7	ARCHER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
8	BEACON HILL - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	BEVILLES CORNER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
10	CARRABELLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	CARRABELLE BEACH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
12	CRAWFORDVILLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
13	CRAWFORDVILLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
14	CROSS CITY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	EAST POINT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	FOLEY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	FORT WHITE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
18	FORT WHITE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	4.00
19	FORT WHITE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
20	G.E. ALACHUA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	GAINESVILLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
22	GEORGIA PACIFIC - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	HIGH SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	HIGH SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	7.00	
25	HULL ROAD - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	INDIAN PASS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	JASPER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
28	JASPER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	JENNINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
30	LURAVILLE -NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	MADISON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
32	MONTICELLO - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	NEWBERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
34	NEWBERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
35	O'BRIEN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	OCCIDENTAL #1 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
37	OCCIDENTAL #1 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	
38	OCCIDENTAL #2 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
39	OCCIDENTAL #3 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
40	OCCIDENTAL SWIFT CREEK#1-NORTHERN FLORIDA	DIST - UNATTENDED	115.00	4.00	

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
						2
						3
13	1	1				4
13	1	1				5
150	1					6
16	2	2				7
13	1	1				8
22	1					9
13	1	1				10
10	1	1				11
100	1					12
13	1	1				13
13	1	1				14
13	1	1				15
40	2					16
100	1					17
75	1					18
6	1	1				19
20	1					20
30	1					21
10	1	1				22
9	1					23
13	1	1				24
19	2					25
5	1	1				26
60	1					27
13	1	1				28
2	1	1				29
9	1	1				30
40	2					31
40	2					32
100	1					33
13	1	1				34
6	1	1				35
50	1					36
25	1					37
40	2					38
13	1					39
60	3					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	OCCIDENTAL SWIFT CREEK#2-NORTHERN FLORIDA	DIST - UNATTENDED	115.00	25.00	
2	OCCIDENTAL SWIFT CREEK#2-NORTHERN FLORIDA	DIST - UNATTENDED	115.00	13.00	
3	OCHLOCKONEE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	PERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
5	PERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	PERRY NORTH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	PORT ST. JOE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
8	PORT ST. JOE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	PORT ST. JOE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
10	RIVER JUNCTION - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	SHAMROCK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	12.00	4.00	
12	SOPCHOPPY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	ST. GEORGE ISLAND - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	ST. MARKS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	SUTTERS CREEK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	SUWANNEE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
17	TRENTON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	UNIVERSITY OF FLORIDA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	23.00	
19	WAUKEENAH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
20	WHITE SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
21	WILLISTON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	WILLISTON TOWN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
23					
24	ADAMS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	ALAFAYA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	ALTAMONTE SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
27	ALTAMONTE SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	APOPKA SOUTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	BARBERVILLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	BAY RIDGE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	BELLEVIEW - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	BEVERLY HILLS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
33	CASSADAGA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
34	CASSELBERRY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	CIRCLE SQUARE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	CITRUS HILL - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
37	CLARCONA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	CLERMONT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	COLEMAN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	CRYSTAL RIVER NORTH -NORTHERN FLORIDA 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) 12/31/2008	Year/Period of Report End of 2008/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.
20	1					1
30	1					2
20	1					3
250	2					4
40	2					5
20	1					6
100	1					7
20	1					8
200	2					9
19	1	1				10
2	1	1				11
9	1	1				12
20	1					13
13	1	1				14
19	2					15
20	1					16
13	1	1				17
90	3					18
9	1					19
2	1	1				20
13	1	1				21
9	1					22
						23
20	1					24
60	2					25
200	1					26
100	2					27
90	3					28
40	2					29
40	2					30
100	2					31
60	2					32
60	2					33
130	3					34
19	2					35
50	2					36
90	3					37
60	2					38
29	2					39
19	1	1				40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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	CRYSTAL RIVER SOUTH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	DELAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	PINE RIDGE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
4	DELAND EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
5	DELTONA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
6	DELTONA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	DELTONA EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	DOUGLAS AVENUE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	DUNNELLON TOWN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	EAGLENEST - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	EATONVILLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	ECON - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
13	EUSTIS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	EUSTIS SOUTH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	FERN PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	GROVELAND - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	HOLDER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	116.00	
18	HOLDER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
19	HOLDER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	14.00	
20	HOMOSASSA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
21	HOWEY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	INGLIS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	
23	INGLIS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	INVERNESS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
25	INVERNESS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	KELLER ROAD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	KELLY PARK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	LADY LAKE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	LAKE ALOMA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	LAKE EMMA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
31	LAKE HELEN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
32	LAKE WEIR - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	LEBANON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
34	LIBSON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	LOCKHART - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
36	LOCKWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	LONGWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	MAITLAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	MARICAMP - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	MARTIN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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.
9	1	1				1
100	2					2
30	1					3
90	3					4
75	1					5
120	3					6
60	2					7
60	2					8
40	2					9
19	2					10
90	3					11
100	2					12
60	2					13
63	2					14
30	1					15
40	2					16
250	1					17
250	1					18
19	2					19
20	1					20
13	1	1				21
100	1					22
9	1					23
160	2					24
60	2					25
60	2					26
9	1					27
29	2					28
100	2					29
100	2					30
55	2					31
19	2					32
10	1	1				33
40	2					34
100	2					35
30	1					36
40	2					37
90	3					38
19	2					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	MCINTOSH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	MINNEOLA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
3	MONTVERDE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
4	MOUNT DORA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	MYRTLE LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
6	NORTH LONGWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
7	NORTH LONGWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
8	OCALA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
9	OCOEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	OKAHUMPKA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	ORANGE BLOSSOM - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	ORANGE CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	14.00
13	ORANGE CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
14	OVIEDO - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	PIEDMONT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
16	PIEDMONT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	PLYMOUTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	PLYMOUTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	14.00	
19	RAINBOW SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	REDDICK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	SANTOS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	SILVER SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
23	SILVER SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	SILVER SPRINGS SHORES - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	SPRING LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	TROPIC TERRACE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
27	TURNER PLANT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
28	TURNER PLANT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	TWIN COUNTY RANCH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	110.00	13.00	
30	TWIN COUNTY RANCH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
31	UNIV OF CENTRAL FL - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	UNIV OF CNTL FL NORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	UMATILLA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	WEIRSDALE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	WEKIVA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
36	WELCH ROAD - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
37	WEST CHAPMAN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	WILDWOOD CITY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	WINTER GARDEN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	WINTER GARDEN CITRUS - SOUTHERN 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) 12/31/2008	Year/Period of Report End of 2008/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.
9	1					1
20	1					2
56	2					3
40	2					4
100	2					5
250	1					6
100	2					7
33	1					8
90	3					9
40	2					10
40	2					11
250	1					12
60	2					13
90	3					14
250	1					15
100	2					16
13	1	1				17
9	1					18
20	2					19
22	2					20
13	1					21
250	1					22
20	1					23
40	2					24
90	3					25
40	2					26
160	2					27
40	2					28
13	1	1				29
9	1					30
60	2					31
60	2					32
40	2					33
19	2					34
100	2					35
100	2					36
60	2					37
25	1					38
100	2					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	12/31/2008	End of 2008/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 GARDEN CITRUS#2 - SOUTHERN FLORIDA	DIST - UNATTENDED	12.00		
2	WINTER GARDEN CITRUS#2 - SOUTHERN FLORIDA	DIST - UNATTENDED	12.00		
3	WINTER PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	WINTER PARK EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
5	WINTER PARK EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
6	WINTER SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
7	WINTER SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	WOODSMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
9	WOODSMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	ZELLWOOD - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	ZUBER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12					
13	AGRICOLA #4 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	ARBUCKLE CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	AVON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
16	AVON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	12.00
17	AVON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	AVON PARK NORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	BABSON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	BARNUM CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	BAY HILL - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	BITHLO - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	BOGGY MARSH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	BONNET CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	CABBAGE ISLAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	CANOE CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	4.00
27	CELEBRATION - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	CENTRAL PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	CHAMPIONS GATE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
30	CITRUSVILLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	CLEAR SPRINGS EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
32	COLONIAL - SOUTHERN FLORIDA REGION	DIST-UNATTENDED	69.00	13.00	
33	CONWAY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	COUNTRY OAKS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	CROOKED LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	14.00	
36	CURRY FORD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
37	CYPRESSWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	DACO - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	DAVENPORT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	DESOTO CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	1					1
5	4					2
120	4					3
500	2					4
100	2					5
250	1					6
90	3					7
250	1					8
40	2					9
40	2					10
29	2					11
						12
9	1					13
8	1					14
200	1					15
150	1					16
40	2					17
40	2					18
20	1					19
60	2					20
90	3					21
50	2					22
100	2					23
60	2					24
60	2					25
30	1					26
60	2					27
90	3					28
20	1					29
20	1					30
20	1					31
30	1					32
40	2					33
40	2					34
10	1					35
50	1					36
40	2					37
13	1					38
20	1					39
19	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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	DINNER LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	DUNDEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	EAST LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	EAST ORANGE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	FISHEATING CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	8.00
6	FISHEATING CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	8.00
8	FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	110.00	14.00
9	FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
10	FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	FOUR CORNERS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	FROSTPROOF - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	HAINES CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	HEMPLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	HEMPLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	HOLOPAW - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	25.00	
17	HORSE CREEK #2 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
18	HUNTERS CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	INTERNATIONAL DRIVE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
20	ISLEWORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	LAKE BRYAN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
22	LAKE BRYAN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	LAKE LUNTZ - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
24	LAKE MARION - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	LAKE OF THE HILLS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	LAKE PLACID - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	LAKE PLACID NORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
28	LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	LAKE WILSON - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	LAKEWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	LEISURE LAKES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	LITTLE PAYNE CREEK#1-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
33	LITTLE PAYNE CREEK#2-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
34	MAGNOLIA RANCH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	MAGNOLIA RANCH TEMP - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
36	MARLEY ROAD - SOUTHERN FLORIDA REGION	DIST- UNATTENDED	69.00	13.00	
37	MEADOW WOODS EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
38	MEADOWS WOODS SOUTH-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
39	MEADOWS WOODS SOUTH-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	MIDWAY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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	2					1
20	1					2
19	2					3
120	3					4
150	1					5
9	1					6
60	1					7
150	1					8
200	1					9
9	1					10
60	2					11
50	2					12
80	2					13
60	1					14
34	1					15
25	2					16
9	1					17
110	3					18
100	2					19
19	2					20
500	2					21
90	3					22
100	2					23
20	1					24
20	1					25
40	2					26
11	2					27
60	2					28
40	2					29
55	2					30
9	1					31
13	1					32
13	1					33
60	2					34
20	1					35
30	1					36
33	1					37
200	1					38
60	2					39
33	1					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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	MULBERRY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	4.00	
2	NARCOOSEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	NORALYN #1 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
4	NORALYN #2 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
5	ODESSA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
6	ORANGEWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	PARKWAY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	PEMBROKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
9	PINECASTLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	POINCIANA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	REEDY LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	RIO PINAR - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
13	RIO PINAR - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	SAND LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	SAND MOUNTAIN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	SEBRING EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	SHINGLE CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	SKY LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
19	SKY LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	SOUTH BARTOW - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	SOUTH FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	
22	SOUTH FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
23	SUNFLOWER - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
24	SUN'N LAKES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	TAFT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	TAUNTON RD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	VINELAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	WAUCHULA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	WEST DAVENPORT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	14.00	
30	WEST LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
31	WEST LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	WESTRIDGE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	WEWAHOOTEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	13.00	4.00	
34	WEWAHOOTEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	WHIDDEN CREEK #1 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
36	WINDERMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
37	WINDERMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38					
39	TOTAL DISTRIBUTION		35591.00	7698.47	360.00
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	12/31/2008	End of 2008/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.
6	1	1				1
90	3					2
9	3	1				3
9	1	1				4
30	1					5
100	2					6
60	3					7
2	1	1				8
40	2					9
100	2					10
40	2					11
500	2					12
100	2					13
80	2					14
9	1	1				15
20	1					16
60	2					17
250	1					18
90	3					19
9	1					20
19	1					21
45	2					22
30	1					23
40	2					24
60	2					25
20	1					26
60	2					27
19	2					28
19	2					29
250	1					30
13	1	1				31
50	1					32
9	1	1				33
13	1	1				34
20	1					35
200	1					36
40	2					37
						38
25567	584	49				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	12/31/2008	End of 2008/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	BROOKRIDGE - COASTAL FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
2	BROOKRIDGE - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
3	BROOKRIDGE - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	133.00	
4	BROOKSVILLE WEST - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
5	HIGGINS PLANT - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
6	HUDSON - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
7	HUDSON - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	7.20
8	LAKE TARPON - COASTAL FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
9	NEW RIVER - COASTAL FLORIDA REGION	TRANS - UNATTTENDED	115.00	69.00	
10					
11	BRONSON - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
12	DRIFTON - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	5.00
13	GINNIE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
14	GUMBAY - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
15	HAVANA - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
16	IDYLWILD - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	138.00	67.00	12.00
17	QUINCY - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	4.00
18	SUWANNEE 230 KV - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
19	TALLAHASSEE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	8.00
20	WILCOX - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
21	LIBERTY - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	
22	ANDERSEN - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	14.00
23	BARBERVILLE - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	66.00	33.00
24	CAMP LAKE - NORTHERN CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	15.00
25	CENTRAL FLORIDA - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
26	CENTRAL FLORIDA - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
27	CLERMONT EAST - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	14.00
28	CRYSTAL RIVER EAST - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	116.00	
29	DALLAS - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
30	DELAND WEST - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
31	DELAND WEST - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	15.00
32	HAINES CREEK - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
33	MARTIN WEST - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
34	ROSS PRAIRIE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
35	ROSS PRAIRIE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
36	SORRENTO - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
37					
38	AVALON - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
39	BARCOLA - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
40	GRIFFIN - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	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	12/31/2008	End of 2008/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.
750	1					1
250	1					2
250	1					3
250	1					4
250	1					5
500	2					6
280	1					7
1500	2	1				8
280	1					9
						10
168	1					11
105	2					12
280	1					13
75	1					14
75	1					15
150	1					16
75	1					17
400	2					18
120	2					19
150	1					20
150	1					21
133	1					22
30	4	1				23
150	1					24
1500	2					25
450	2					26
250	1					27
250	1					28
280	1					29
200	1					30
125	1					31
250	1					32
200	1					33
150	1					34
280	1					35
250	1					36
						37
250	1					38
150	1					39
250	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	12/31/2008	End of 2008/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	INTERCESSION CITY - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
2	INTERCESSION CITY - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	13.00
3	KATHLEEN - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
4	NORTH BARTOW - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
5	SOUTH POLK - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
6	VANDOLAH - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	23.00
7					
8	TOTAL TRANSMISSION		10236.00	4124.00	260.20
9					
10					
11					
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					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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
280	1					2
750	1					3
150	1					4
168	1	1				5
400	2					6
						7
13204	55	3				8
						9
						10
						11
						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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

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.

INDEX

Schedule	Page No.

INDEX (continued)

Schedule — Page No.

Schedule	Page No.

INDEX (continued)

Diversification Report

Progress Energy Florida Inc.

December 31, 2008

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, 2008 to December 31, 2008, inclusive.

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

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

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

4/29/09
Date

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, 2008

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
Frank A. Schiller	General Counsel	Director	Capitan Corporation
		Director	Carofund, Inc.
		Director	Florida Progress Funding Corporation
		Director	PIH Tax Credit Fund III, Inc.
		Director	PIH Tax Credit Fund IV Inc.
		Director	PIH Tax Credit Fund V, Inc.
		Director	PIH, Inc.
		Director	Progress Energy Envirotree, Inc.
		Director	Progress Reinsurance Company, Ltd.
		Director	Progress Synfuel Holdings, Inc.
		Director	Progress Telecommunications
		Director	Stratetic Resource Solutions, Inc.
James Scarola	Sr. Vice President	Board Member	Parr Shoals Reactor (Carolina/Virginia Corp Board)
		Board Member	University of South Carolina's Nuclear Engineering Advisory Board
Jeffrey J. Lyash	President	Director	Enterprise Florida, Inc., Orlando, FL
		Director	Florida Chamber of Commerce
		Trustees	Florida Chamber of Commerce Foundation, Inc.
		Director	SunTrust Bank, Tampa, FL
		Director	The Southeastern Electric Exchange
		Director	The Florida Orchestra, Tampa, FL
		Director	Florida Reliability Coordinating Council (FRCC), Tampa, FL
		Director	Tampa Bay Partnership, Tampa, FL
		Executive Committee	Florida Electric Power Coordinating Group (FCG), Tampa, FL
		Director	The Florida Council of 100, Tampa, FL
		Trustees	Florida Chamber of Commerce Foundation, Inc.
Jeffrey M. Stone	Chief Accounting Officer	None	
John R. McArthur	Senior Vice President	PGN Representative	American Coalition for Clean Coal Electricity (ACCCE)
		Board of Directors	Carolina Power & Light Company, DBA Progress Energy , Carolinas, Inc.
		Board of Directors	Florida Power Corporation
		Board of Directors	Florida Progress Corporation
		Board of Directors	Global Transpark Foundation, Inc., Kinston, NC
		Board of Directors	Progress Capital Holdings, Inc.
		Board of Directors	Progress Energy Foundation, Inc.
		Board of Directors	Progress Energy Service Company, LLC
		Board of Directors	Progress Energy, Inc.
		Board of Directors	Progress Fuels Corporation
		Board of Directors	Progress Telecommunications Corporation
		Board of Directors	Progress Ventures, Inc.
		Board of Directors	PV Holdings, Inc.
		Board of Directors	Strategic Resource Solutions
Lloyd Yates	President and CEO, PGN Carolinas	Board Member	Association of Edison Illuminating Companies
		Chairman	Triangle Urban League
		Board Member	North Carolina Community College Foundation Board
		Board Member	North Carolina Economic Development Committee
		Board Member	High Five Board
Mark Mulhern	Chief Financial Officer	Director	Dulcimer Land Company, Inc.
		President	Kanawha River Terminals, Inc.
		President	Kentucky May Coal Company, Inc.
		President	Marigold Dock, Inc.
		Board Member	Microcell
		President	Powell Mountain Coal Company, Inc.
		President	Progress Fuels Corporation
		President	Progress Synfuel Holdings, Inc.
		President	Progress Ventures, Inc.
		President	PV Holdings, Inc.
Michael Lewis	Sr. Vice President, Energy Delivery	Board Member	Pinellas Association for Retarded Citizens
		Board Member	Economic Development Council
		Board Member	Junior Achievement of West Central Florida
		Governors Council	Metro Orlando Economic Development Commission
		Board Member	Pinellas Education Foundation

		Member	University of Florida Engineering Advisory Council
Paula J. Sims	Senior Vice President		Meredith College Board of Trustees
Thomas R. Sullivan	Vice President, Treasurer	None	
Will A. Garrett	Controller	None	
William D. Johnson	Chairman and CEO	Board Member	Daugherty Endowment Fund, Raleigh, NC
		Board Member	Rex Hospital, Raleigh, NC
		Chairman	Carolina Power & Light Company, DBA Progress Energy Carolinas
		Director	Edison Electric Institute
		CEO	Edison Electric Institute- Task force on Electric Transportation
		Board Member	Edison Electric Institute- Climate Change Task Force
		Chairman	Florida Power Corporation- DBA Progress Energy Flroida
		CEO	Florida Progress Corporation
		Director	Institute of Nuclear Power Operations
		Board Member	North Carolina Chamber Board
		Chairman	Progress Capital Holdings, Inc.
		President	Progress Energy Foundation
		CEO	Progress Energy, Inc.
		Chairman	Progress Fuels Corporation
		Chairman	PV Holdings, Inc
		Chairman	Progress Ventures, Inc.

Business Contracts with Officers, Directors and Affiliates

Company:
For the Year Ended December 31, 2008

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
Jeffrey J. Lyash	Tampa Bay Partnership Inc	8,000	Donations
Jeffrey J. Lyash	The Florida council of 100	4,000	Dues
Jeffrey J. Lyash	Boys & Girls Club of the Suncoast	15,000	Donations
Jeffrey J. Lyash	Boys & Girls Clubs of Central Florida	25,000	Donations
Jeffrey J. Lyash	Florida Chamber of Commerce	5,000	Dues
Michael A. Lewis	Pinellas County Education Foundation	8,000	Donations
Jeffrey J. Lyash	The Florida Orchestra	36,000	Donations

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

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

For the Year Ended December 31, 2008

For the current year, reconcile the gross operating revenues as reported on Page 300 of this report with the gross operating revenues as reported on the utility's regulatory assessment fee return. Explain and justify any differences between the reported gross operating revenues in column (h).

Line No.	(a) Description	(b) Gross Operating Revenues per Page 300	(c) Interstate and Sales for Resale Adjustments	(d) Adjusted Intrastate Gross Operating Revenues	(e) Gross Operating Revenues per RAF Return	(f) Interstate and Sales for Resale Adjustments	(g) Adjusted Intrastate Gross Operating Revenues	(h) Difference (d) - (g)
1	Total Sales to Ultimate Customers (440-446, 448)	$ 4,002,713,138	$ 39,669,827	$ 3,963,043,311	$ 4,002,713,138	$ 39,669,827	$ 3,963,043,311	$ -
2	Sales for Resale (447)	548,740,573	548,740,573	-	548,740,573	548,740,573	-	0
3	Total Sales of Electricity	4,551,453,711	588,410,400	3,963,043,311	4,551,453,711	588,410,400	3,963,043,311	0
4	Provision for Rate Refunds (449.1)	(1,474,329)	(1,474,329)	-	(1,474,329)	(1,474,329)	-	0
5	Total Net Sales of Electricity	4,549,979,382	586,936,071	3,963,043,311	4,549,979,382	586,936,071	3,963,043,311	0
6	Total Other Operating Revenues (450-456)	180,911,106	47,827,339	133,083,767	180,911,106	47,827,339	133,083,767	-
7	Other (Specify)							
8								
9								
10	**Total Gross Operating Revenues**	$ 4,730,890,488	$ 634,763,410	$ 4,096,127,078	$ 4,730,890,488	$ 634,763,410	$ 4,096,127,078	$ -

Analysis of Diversification Activity
Changes in Corporate Structure

Company:

For the Year Ended December 31, 2008

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)
1/7/2008	Kanawha River Terminals, Inc.'s interest in Colona Synfuel, LLLP increased to 61.9% (from 12.1%).
2/27/2008	Kanawha River Terminals, Inc. was converted to a single-member LLC and became Kanawha River Terminals, LLC.
2/28/2008	Kentucky May Coal Company, Inc. was converted to a single-member LLC and became Kentucky May Coal Company, LLC.
2/29/2008	Kanawha River Terminals, LLC distributed its 61.9% interest in Colona Synfuel, LLLP to Progress Fuels Corporation, Corporations, and also its subsidiaries to Progress Fuels.
3/6/2008	Kentucky May Coal Company sold Kanawha River Terminals, LLC .
3/6/2008	Progress Fuels Corporation sold Powell Mountain Coal Company, Inc. and Dulcimer Land Company, Inc. to a third party.
4/28/2008	Progress Energy Florida became a 53.0049% member of SanGroup, LLC, a newly-formed entity.
5/22/2008	Progress Energy Carolinas' and Progress Energy Florida's ownership interest in APOG, LLC became 10% each.
7/2/2008	Progress Capital Holdings, Inc. shares (3,375,000 shares of Series A) in Cadence Network, Inc. were cancelled.
8/31/2008	ITAC 27,LLC was merged into its parent, Progress Energy Carolinas.
9/9/2008	New Broad River, LLC was dissolved.
9/18/2008	PEC Broad River, LLC was dissolved.
9/8/2008	Coal Recovery V, LLC was dissolved.
11/6/2008	New River Synfuel LLC was dissolved.
11/28/2008	A certificate of Dissolution was issued by the Cayman Islands Registrar of Companies. (Effective date 03/02/2009)
11/30/2008	Solid Fuel LLC was dissolved.
11/30/2008	Solid Energy LLC was dissolved.
11/30/2008	Sandy River Synfuel LLC was dissolved.
11/30/2008	Colona Synfuel Limited Partnership LLLP was dissolved.
12/31/2008	Blackhawk Synfuel LLC was dissolved.
12/31/2008	PV Synfuels LLC was dissolved.
12/31/2008	Marmet Synfuel LLC was dissolved.
12/31/2008	AAV Synfuel LLC was dissolved.
12/31/2008	Riverside Synfuel LLC was dissolved.
12/31/2008	EFC Synfuel LLC was dissolved.
12/31/2008	Colona Newco LLC was dissolved.
12/31/2008	Colona Sub No. 2 LLC was dissolved.

Analysis of Diversification Activity

New or Amended Contracts with Affiliated Companies

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2008

Provide a synopsis of each new or amended contract, agreement, or arrangement with affiliated companies for the purchase, lease, or sale of land, goods, or services (excluding tariffed items). The synopsis shall include, at the minimum, the terms, price, quantity, amount, and duration of the contracts.

Name of Affiliated Company (a)	Synopsis of Contract (b)
No new or amended affiliated contracts in 2008.	

Analysis of Diversification Activity

Individual Affiliated Transactions in Excess of $500,000

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2008

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 (as service provider)	Recurring monthly Service Company functions and services. See Page 457 for description.	$ 165,279,889
Progress Energy Service Company LLC (as customer)	Non-recurring sale of personal computers	12,036,035
Progress Energy Service Company LLC (as customer)	Recurring monthly shared functions and services. See page 457 for description.	6,058,124
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)(as service provider)	Recurring monthly shared utility functions and services. See page 457 for description.	42,101,120
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)(as service provider)	Recurring monthly nuclear licensing support.	1,595,793
Carolina Power & Light Company (as customer)	Non-recurring nuclear refueling outage assistance	1,850,037
Carolina Power & Light Company (as customer)	Recurring monthly shared utility functions and services. See page 457 for description.	10,017,857

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2008

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	Utility Service Agreement 1/1/2001	S	1460001	11,867,894
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Shared utility functions and services such as nonreg transmission maintenance service, ECCR energy efficiency support, retail energy sales support, premier power support, PPS managed services support, transmission/distribution support, ED management/ovrsight, contract services, customer service management, performance solutions, nuclear management, nuclear IT, nuclear analytical services, common nuclear services, nuclear security support, regulatory assessment/oversight, engineering programs, materials and contract support, coal procurement and transportation, power ops management and finance, techical services support, CT ops/maintenance RCO purchased power contract support, RCO joint owner contract support, RCOoperational support, RCO wholesale term contract support, RCO gas and oil procurement, regulated lighting support, exterio lighting support, fuel forecasting and regulatory support.	Utility Service Agreement 1/1/2001	P	2340001	43,696,913
PT Holding Company LLC	Network Services, Land Lease, Revenue Sharing	Master Service and Wireless Attachment Agreements - 12/19/2003	S	1460071	2,758,771
Progress Energy Ventures	Technical, Support & Training Svcs, CT Operations & Maintenance support, CT Performance Improvement support	Utility Service Agreement 11/1/2002	S	1460073	764
Progress Energy Service Company LLC	Labor and associated expenses, materials, personal computers	Utility Service Agreement 1/1/2001; Amendment to Article IV effective 10/18/2007	S	1460098	18,094,159
Progress Energy Service Company LLC	Executive Management, Legal, IT, Accounting Svcs, Audit Svcs, Planning, Telecom, Public Affairs, Human Resources, Corp Communications, Security, Supply Chain Svcs, Real Estate Svcs, Tax Svcs, Risk Mgmt, Environmental Svcs, Health & Safety Svcs, Treasury, Risk Mgmt, Disbursement Svcs, Other Shared Corp Svcs. Excludes convenience payments and pay agent transactions.	Utility Service Agreement 12/1/2000	P	2340098	165,279,889

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

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2008

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

Name of Affiliate	Description of Asset or Right	Cost/Orig. Cost	Accumulated Depreciation	Net Book Value	Fair Market Value	Purchase Price	Title Passed Yes/No
Purchases from Affiliates:							
None							
Total		$ -	-	$ -	$ -	$ -	
Sales to Affiliates:		$	$	$	$	**Sales Price**	
Progress Energy Service Company LLC	Non-recurring sale of personal computers	11,999,485.00	-	11,999,485.00	11,999,485.00	12,036,034.99	**
*****Sales price includes carrying charge to PESC***							
Total						$ 12,036,034.99	

Analysis of Diversification Activity
Employee Transfers

Company: Progress Energy Florida, Inc.
For the Year Ended December 31, 2008

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

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
SVC	FPC	Security Spec	Security Spec	Permanent
FPC	CPL	Dir-CombustionTurbine Svcs	Plant Mgr-Lee/Wayne CT	Permanent
CPL	FPC	Plant Services Asst I	Technical Support Asst II-FL	Permanent
SVC	FPC	Bus Fin Anlyst	Sr Bus Fin Anlyst	Permanent
CPL	FPC	Princ Tech Proj Mgmt Spec-POG	Princ Tech Proj Mgmt Spec-POG	Permanent
SVC	FPC	Generation Comm Spec-CR3	Mgr-Community Rels	Permanent
SVC	FPC	Sr Security Spec	Sr Security Spec	Permanent
FPC	CPL	Mgr-Distribution Ops	Mgr-Distribution Ops	Permanent
CPL	FPC	Sr Engr	Sr Engr	Permanent
CPL	FPC	Gen Mgr-Distribution	Gen Mgr-LevyBaseLoadTransProg	Permanent
CPL	FPC	Relay Tech I	Sr Craft/Technical Trainer	Permanent
FPC	CPL	Sr VP-Energy Delivery-FL	Sr VP-Energy Delivery-Carolina	Permanent
CPL	FPC	Plant Mgr-Mayo	Plant Mgr-Crystal River	Permanent
FPC	CPL	Lead Enrgy Del Process Anlyst	Lead Enrgy Del Process Anlyst	Permanent
SVC	FPC	Mgr-Inv and Phys Security	Mgr-Inv and Phys Security	Permanent
CPL	FPC	Dir-Perf Solutions-ED	LINC Proj Mgr	Permanent
CPL	FPC	Sr Plt Const Proj Mgr-POG	Sr Plt Const Proj Mgr-POG	Permanent
FPC	CPL	Mgr-Meter & Energy Sys	Mgr-Meter & Energy Sys	Permanent
CPL	FPC	Mgr-Distribution Ops	Mgr-Distribution Ops	Permanent
CPL	FPC	Supv-Electrical/I&C Maint-Nuc	Sr Nuc Tech Proj Mgmt Spec	Permanent
FPC	SVC	Administrative Assistant I-FL	Admin Assistant I	Permanent
SVC	FPC	Sr Bus Fin Anlyst	Sr Bus Fin Anlyst	Permanent
CPL	FPC	Princ Tech Proj Mgmt Spec-POG	Princ Tech Proj Mgmt Spec-POG	Permanent
FPC	SVC	Administrative Assistant II-FL	Legal Secretary I-FL	Permanent
SVC	FPC	Logistics Planning Anlyst	Sr Work Mgmt Spec	Permanent
FPC	SVC	Matls & Inv Tech I	Matls & Inv Tech I	Permanent
SVC	FPC	Administrative Assistant I-FL	Administrative Assistant I-FL	Permanent
FPC	SVC	Nuc Instruct Tech-NGG	Workforce Program Spec	Permanent
CPL	FPC	Lead Tech Proj Mgmt Spec-POG	Lead Tech Proj Mgmt Spec-POG	Permanent
CPL	FPC	Tech Proj Mgmt Spec-POG	Tech Proj Mgmt Spec-POG	Permanent
SVC	FPC	Lead Security Spec	Lead Security Spec	Permanent
FPC	CPL	Lineman	Line & Serv Tech 1/C	Permanent
SVC	FPC	Mgr-Risk Analytics & Reporting	Mgr-PEF Ener Delivery Finance	Permanent
FPC	SVC	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
SVC	FPC	Mgr-Capital Planning & Control	Mgr-PEF Planning & Strategy	Permanent
SVC	FPC	Sr Human Resources Spec	Sr ED Project Analyst	Permanent
FPC	SVC	Mtls & Inv Tech II	Mtls & Inv Tech II	Permanent
FPC	CPL	Gen Mgr-Distribution	Dir-Resource Mgmt&Constr (IO)	Permanent
CPL	FPC	Supt-Operations & Results-FGD	Mgr-Shift Operations-CR	Permanent
FPC	SVC	Sr Occ Health & Safety Spec	Sr Auditor	Permanent
SVC	FPC	Public Policy Analyst-CRAS	Sr ED Project Analyst	Permanent
FPC	SVC	Customer Service Agent I-FL	IT Trainee-IT&T	Permanent
CPL	FPC	Shift Supv-FGD	Shift Supv-FGD	Permanent
FPC	CPL	Supv-Nucl Site Security Trning	Mgr--Nuclear Plant Security	Permanent
FPC	CPL	Sr Access Authorization Spec	Sr Access Authorization Spec	Permanent
FPC	SVC	Telecomm Tech (S)	Telecomm Tech II	Permanent
SVC	FPC	Data Mgmt Asst II	Data Mgmt Asst II	Permanent
FPC	CPL	Mgr-Plant General CRP	Dir-Site Opers-BNP	Permanent
FPC	CPL	Plt Mgr-CT-Central	Mgr-Contin Bus Excellence (IO)	Permanent
FPC	SVC	Mgr-Employee Development	Lead Project Assurance Advisor	Permanent
SVC	FPC	Supv-PEF Reg Planning Projects	Mgr-PEF Generation Finance	Permanent
SVC	FPC	Sr Security Spec	Sr Security Spec	Permanent
CPL	FPC	I&C Tech I-Nuc	Electrician-SM	Permanent

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

Company: Florida Power Corporation

For the Year Ended December 31, 2008

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

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2008

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of nonutility property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor items (5% of the balance at the end of the year, for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service, or (2) other property nonutility property.

Description and Location	Balance at beginning of year	Purchases, Sales, Transfers, etc.	Balance at end of year
Previously Devoted to Public Service			
Land - Marion County - Florida	$ 135,191		$ 135,191
Structures - Pinellas County, Florida	177,011		177,011
Minor Items	527,365		527,365
Not Previously Devoted to Public Service			
Land - Volusia County, Florida	1,622,391		1,622,391
Equipment - Meters System (Florida)	5,423,549		5,423,549
Equipment - Walk of Fame, St. Pete, FL	1,380,193		1,380,193
Other	325,828		325,828
Generators on Customer premises	732,987		732,987
Communication Equipment	0		0
Totals	$ 10,324,515	$ -	$ 10,324,515

Number of Electric Department Employees

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

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	**10/26/2008**
2. Total Regular Full-Time Employees	**4107**
3. Total Part-Time and Temporary Employees	**185**
4. Total Employees	**4292**

Details

Regular Part Time:	6
Temp Full Time:	176
Temp Part Time:	3
Total:	**185**

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Company: Florida Power Corporation
For the Year Ended December 31, 2008

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

(a) Miscellaneous Amortization (Account 425) -- Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Item	Amount
Account 426 - Miscellaneous Income Deductions	
Donations	
Civic & Community Organizations	380,481.73
Cultural & Art Organizations	803,105.53
Economic Development	551,932.89
Education Related Contributions	1,590,254.12
Educational Institutions & Charitable Organziations	3,500,000.00
Environment	199,011.75
Health & Human Services Contributions	709,564.66
Other	18,234.54
Subtotal Accounts 426100F, 4261014, 426180T	7,752,585.22
Investment in Company Owned Life Insurance	8,665,920.72
Subtotal Accounts 4262016, 4262041	8,665,920.72
Penalties	(1,355,072.00)
Subtotal Account 4263001	(1,355,072.00)
Certain Civic, Political & Related Activities	3,035,619.69
Subtotal Accounts 4264200, 4264300	3,035,619.69
Other Deductions	1,457,357.67
Subtotal Accounts 4265001, 4265007	1,457,357.67
Total Miscellaneous Income Deductions - Account 426	19,556,411.30
Account 430 - Interest of Debt to Associated Companies	
Money Pool (Avg Rate 3.29%)	1,247,194.87
Total Interest on Debt to Associated Companies - Account 430	1,247,194.87
Account 431 - Other Interest Expense	
Commitment Fees (4310010)	378,117.45
Other Interest Expense (4310001, 4310011)	1,838,916.88
Customer Deposits - Rate 6 to 7% per annum	11,300,460.23
Interest related to OPC Petition Customer Refund - Rate 2.61%	221,293.00
Interest related to Projected Tax Deficiency on various audit issues - Rate - 6.9%	(5,766,357.71)
Total Other Interest Expense - Account 431	7,972,429.85

Budgeted and Actual In-Service Costs of Nuclear Power Plant

Company: Progress Energy - Florida
For the Year Ended December 31, 2008

[Section (8)(f)]

Report the budgeted and actual costs as compared to the estimated in-service costs of the proposed power plant as provided in the petition for need determination or revised estimate as necessary. Per Rule 25-6.0423(8)(f)

Item

Plant Name: Levy County Nuclear Unit 1 and 2

	Actual Costs as of December 31, (insert year): 2008	Remaining Budgeted Costs to Complete Plant:	Total Estimated Cost of Plant	Note 1 Estimated Cost provided in the Petition for Need Determination (or revised estimate as necessary)
Licensing/Permits/Authorizations/Legal	$ 56,754,580	$ (56,754,580)	$ -	$ -
Site/Site Preparation	$ 64,350,370	$ (64,350,370)	$ -	$ -
Related Facilities	$ 418,519	$ (418,519)	$ -	$ -
Generation Plant	$ 110,684,010	$ 11,729,915,990	$ 11,840,600,000	$ 10,843,097,000
Transmission Facilities	$ 10,506,278	$ 2,012,593,722	$ 2,023,100,000	$ 2,446,841,000
AFUDC	$ 16,026,216	$ 3,366,273,784	$ 3,382,300,000	$ 3,876,236,000
Total	$ 258,739,973	$ 16,987,260,027	$ 17,246,000,000	$ 17,166,174,000

Note 1: These amounts are based on our Need Determination which was filed March 11, 2008. At that point PEF did not have negotiated or signed contracts in place. Therefore the estimates provided are high level and only broken out between generation and transmission as presented in the Need Petition. As the project continues PEF will have better estimates and contracts in place.

Budgeted and Actual In-Service Costs of Nuclear Power Plant

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

For the Year Ended December 31, 2008

Report the budgeted and actual costs as compared to the estimated in-service costs of the proposed power plant as provided in the petition for need determination or revised estimate as necessary. Per Rule 25-6.0423(8)(f)

Item	Actual Costs as of December 31, (insert year): 2008	Remaining Budgeted Costs to Complete Plant:	Total Estimated Cost of Plant Note (1)	Estimated Cost provided in the Petition for Need Determination (or revised estimate as necessary) Note (2)
Plant Name: Crystal River Unit 3 Uprate				
Licensing/Permits/Authorizations/Legal	$ -	$ 17,691,319	$ 17,691,319	$0
Site/Site Preparation	$ -	$ -	$ -	0
Related Facilities Note (3)	$ -		$ -	49,450,000
Generation Plant	$ 105,457,792	$ 228,737,453	$ 334,195,245	287,500,000
Transmission Facilities	$ -	$ -	$ -	102,350,000
Total	$ 105,457,792	$ 246,428,771	$ 351,886,563	$ 439,300,000

(1) Estimated costs included herein are exclusive of Cost of Removal.

(2) Estimated costs provided in the petition for need determination are based on estimates provided in CR3 Power Uprate Need proceeding, Docket # 060642-EI. These numbers have been increased by 15% for indirect costs to make them comparable to the estimated cost of plant amounts which also include the indirect costs.

(3) Related Facilities included the POD project balance per the Need Determination, but for schedule purposes, these costs are captured within the Generation Plant line item.