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

EI801-05-AR

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

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Florida Power Corporation	End of 2005/Q4

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

GENERAL INFORMATION

I Purpose

Form 1 is an annual regulatory support requirement under 18 CFR 141.1 for Major public utilities, licensees and others. Form 1-F is an annual regulatory support requirement under 18 CFR 141.2 for Nonmajor public utilities, licensees and others. Form 3-Q is a quarterly regulatory support requirement which supplements Forms 1 and 1-F under 18 CFR 141.400. The reports are designed to collect financial and operational information from major and nonmajor electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 CFR 101), must submit Form 1 as prescribed in 18 CFR Part 141.1. Each Nonmajor electric utility, licensee or other must submit Form 1-F as prescribed in 18 CFR Part 141.2. Each Major and Nonmajor electric utility licensee or other, must submit Form 3-Q as prescribed in 18 CFR Part 141.400.

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:
(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus Losses).

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

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

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

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

(d) For the Annual CPA certification, submit with the original submission, or within 30 days after the filing date for Form 1, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):
(i) Attesting to the conformity, in all material aspects, of the below listed (schedules and) pages with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
(ii) be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 CFR 158.10-158.12 for specific qualifications.)

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

Insert the letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the address indicated at III (b). Use the following form for the letter or report unless unusual circumstances or conditions, explained in the Letter or report, demand that it be varied. insert parenthetical phrases only when exceptions are reported.

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

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

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

.

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

IV. When to Submit:

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information.public reporting burden for the Form 1-F collection of information is estimated to average 112 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 150 hours per response. Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Mr. Michael Miller, ED-30); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. 3512 (a)).

GENERAL INSTRUCTIONS

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

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

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

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

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

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

VII For any resubmissions, submit the electronic filing using the Form 1/3-Q software and send a letter identifying which pages in the form have been revised. Send the letter to the Office of the Secretary.

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

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

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

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.
FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.
LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.
OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.
SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.
NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.
OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service form. Describe the type of service in a footnote for each entry.
AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

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

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

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

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to wit: ... (3) . corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shalt not include 'municipalities, as hereinafter defined;

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

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

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

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

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

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

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

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

GENERAL PENALTIES

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
Florida Power Corporation	End of 2005/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)*
100 Central Avenue, St. Petersburg, FL 33701-3324

05 Name of Contact Person	06 Title of Contact Person
Lori Cross	Manager-Regulatory Planning

07 Address of Contact Person *(Street, City, State, Zip Code)*
100 Central Avenue, St. Petersburg, FL 33701-3324

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(727) 820-5128	(1) ☒ An Original (2) ☐ A Resubmission	12/31/2005

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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Peter M. Scott III	Peter M Scott III	04/18/2006
02 Title: Chief Financial Officer	Peter M. Scott III	

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) 12/31/2005	Year/Period of Report End of 2005/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	12/31/2005	End of 2005/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	12/31/2005	End of 2005/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
100 Central Avenue
St. Petersburg, FL 33701-3324

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	12/31/2005	End of 2005/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) 12/31/2005	Year/Period of Report End of 2005/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)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	Geoffrey S. Chatas, Executive Vice President	PO Box 1551, Raleigh, NC 27602
2	Fred N. Day, IV, Executive Vice President	PO Box 1551, Raleigh, NC 27602
3	H. William Habermeyer, Jr., President and CEO	100 Central Avenue, St. Petersburg, FL 33701
4	William D. Johnson, Executive Vice President	PO Box 1551, Raleigh, NC 27602
5	Jeffrey J. Lyash, Senior Vice President	100 Central Avenue, St. Petersburg, FL 33701
6	John R. McArthur, Senior Vice President	PO Box 1551, Raleigh, NC 27602
7	Robert B. McGehee, Chairman	PO Box 1551, Raleigh, NC 27602
8	William S. Orser, Group President	PO Box 1551, Raleigh, NC 27602
9	Peter M. Scott III, Executive Vice President	PO Box 1551, Raleigh, NC 27602
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11	Note: Florida Power Corporation Board does not have an	
12	Executive Committee.	
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Schedule Page: 105 Line No.: 1 Column: a

Resigned from the Board effective November 14, 2005.

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

Elected to the Board effective December 12, 2005.

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

Elected to the Board effective December 12, 2005.

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

Resigned from the Board effective April 1, 2005.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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 year ended December 31, 2005, one (1) new franchise was signed with the City of Bartow with whom the company did not previously have an existing agreement. The agreement has a 30-year term and does not contain a purchase option.

The Town of Redington Shores increased its franchise fee from 4% to 6% which is allowable under the existing agreement between the Town and Progress Energy.

The franchise between Progress Energy and the City of Orlando expired on February 13, 2005. Progress Energy serves just 2400 customers in the City. The expired agreement did not include a purchase option. At December 31, 2005 discussions are in progress with the City for a new agreement.

One new (1) franchise was signed with the City of Edgewood. Prior to this agreement, the last franchise held with the City of Edgewood expired in 2000. The 2005 agreement has a 30-year term, a 6% franchise fee and a purchase option.

A franchise was renewed with the City of Maitland. This agreement is a 30-year agreement with a 6% franchise fee and a purchase option.

One (1) new franchise was signed with the City of Carrabelle. Prior to this agreement, the last franchise held with the City of Carrabelle was due to expire in 2007. The 2005 agreement has a 30-year term and a 6% franchise fee.

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

2. ACQUISITION OF OWNERSHIP IN OTHER COMPANIES

None

3. PURCHASE OR SALE OF AN OPERATING UNIT OR SYSTEM

On June 1, 2005, the Company finalized the sale of Electric Distribution Assets within the city limits of Winter Park to the City of Winter Park for a total sale price of $41,718,447. The sale was recorded in Account 102 - Electric Plant Purchased or Sold, in accordance with the provisions of that account and Electric Plant Instruction No. 5 of the Uniform System of Accounts 18CFR Part 101 (2004). Journal entries related to this sale were submitted for approval to the Federal Energy Regulatory Commission on July 12, 2005. On October 6, 2005 these journal entries were approved by the Federal Energy Regulatory Commission and a gain on sale of $24,287,864 was recorded.

4. IMPORTANT LEASEHOLDS

None

5. IMPORTANT EXTENSION OR REDUCTION TO TRANSMISSION OR DISTRIBUTION SYSTEM

On June 1, 2005, the Company finalized the sale of Electric Distribution Assets within the city limits of Winter Park to the City of Winter Park for a total sales price of $41,718,447. The Net Book Value of the distrubtion assets sold was $8,795,374. The estimated loss of customers is 13,000. The approximate estimated loss of annual revenues is $35.1M (based on 2004 revenues) and relates to the following rate classes: $17.5M Residential, $15.5M Commercial, $1.9M Public Authority and $0.2 Industrial.

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

(a) During the year ended December 31, 2005, Florida Power Corporation issued $2,846,233,000 in commercial paper and redeemed a total of $2,867,100,000. The average daily weighted yield during the period was 3.481586.

(b) As of December 31, 2005, the Company's revolving credit facilities totaled $450 million, all of which supports it commercial paper borrowing and other short-term obligations. The Company entered into a new $450 million (5-year) RCA, which replaced a 364-Day Credit Agreement, dated as of April 1, 2003, as amended and restated, for $200 million; and a 3-Year Credit Agreement, dated as of April 1, 2003, for $200 million. The Company is required to pay minimal annual commitment fees to maintain its credit facilities.

(c) In January 2005, the Company used proceeds from the issuance of commercial paper to pay off $170 million of revolving credit agreement (RCA) loans and in February 2005, the Company used proceeds from money pool borrowings to pay $55 million of RCA loans.

(d) On May 16, 2005, the Company issued $300 million of First Mortgage Bonds, 4.50% Series due 2010. The net proceeds from the sale of the bonds were used to reduce the outstanding balance of commercial paper.

(e) On July 1, 2005, the Company paid at maturity $45 million of its 6.72% Medium-Term Notes, Series B with short-term debt proceeds.

(f) On July 28, 2005, the Company filed a shelf registration statement with the SEC to provide an additional $1.0 billion of capacity in addition to the $450 million remaining on the Company's current shelf registration statement. The registration statement was declared effective on December 23, 2005, and will allow the Company to issue various securities, including First Mortgage Bonds, Debt Securities and Preferred Stock.

(g) On December 13, 2005, the Company issued $450 million of Series A Floating Rate Senior Notes due 2008. Interest on the Floating Rate Senior Notes will be based on three-month LIBOR plus 40 basis points and will be reset quarterly. The net proceeds from the sale of the bonds were used to reduce the outstanding balance of short-term debt, including commercial paper borrowings and borrowings under our internal money pool, and for general corporate purposes.

Authorization of items under Note 6 relating to the issuance of bonds, preferred stock and debentures was received from the Florida Public Service Commission under Order PSC-04-1183-FOF-EI.

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

None

9. LEGAL PROCEEDINGS

See Part I, Item 3. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Annual Report on Form 10-K for the year-ended December 31, 2005.

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>

C.H. Cline, Jr., VP	Retired January 1, 2005
Joseph W. Donahue, VP	Elected January 1, 2005
Rodney E. Gaddy, VP	Elected January 1, 2005

Sarah S. Rogers, VP	Elected January 1, 2005
Paula J. Sims, VP	Elected January 1, 2005
William S. Orser, Group President	Retired April 1, 2005
Robert H. Bazemore, Jr., Controller	Reassigned June 1, 2005
Robert M. Williams, Assistant Secretary	Retired June 1, 2005
Jeffrey A. Corbett, VP	Added April 4, 2005
Jeffrey M. Stone, Controller	Added June 1, 2005
Arlene S. Graves, Asst. Secretary	Added June 27, 2005
Laura M. Boisvert, Vice President	Elected September 19, 2005
Sherri L. Daughtridge, Assistant Treasurer	Elected September 26, 2005
David A. Phillips, Vice President	Removed September 9, 2005
Geoffrey S. Chatas – Chief Financial Officer	Removed November 14, 2005
Geoffrey S. Chatas – Executive Vice President	Removed November 14, 2005
William A. Garrett – Controller	Elected November 7, 2005
C. S. Hinnant – Chief Nuclear Officer	Elected November 28, 2005
Peter M. Scott III – Chief Financial Officer	Elected November 14, 2005
Jeffrey M. Stone – Chief Accounting Officer	Elected November 28, 2005
Jeffrey M. Stone – Controller	Removed November 7, 2005
Thomas R. Sullivan – Vice President	Elected November 28, 2005

<u>Director Changes:</u>

William S. Orser	Resigned April 1, 2005
Geoffrey S. Chatas	Removed November 14, 2005
Jeffrey J. Lyash	Elected December 12, 2005
John R. McArthur	Elected December 12, 2005

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	12/31/2005	End of 2005/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	8,789,013,695	8,395,323,055
3	Construction Work in Progress (107)	200-201	385,036,594	419,736,394
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,174,050,289	8,815,059,449
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,272,984,516	4,187,956,959
6	Net Utility Plant (Enter Total of line 4 less 5)		4,901,065,773	4,627,102,490
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	851,954	415,230
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		6,110,241	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		98,974,953	103,060,264
10	Spent Nuclear Fuel (120.4)		49,800,071	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	80,246,740	58,232,497
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		75,490,479	45,242,997
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,976,556,252	4,672,345,487
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)		19,431,391	19,254,493
19	(Less) Accum. Prov. for Depr. and Amort. (122)		10,976,032	7,961,499
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	1,750	0
24	Other Investments (124)		512,616	357,724
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		531,424,415	497,704,806
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		45,357,164	2,400,444
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		585,751,304	511,755,968
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		12,687,600	10,973,321
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		203,386,579	0
39	Notes Receivable (141)		1,341,415	1,308,073
40	Customer Accounts Receivable (142)		252,584,609	189,689,778
41	Other Accounts Receivable (143)		24,500,384	12,625,412
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,870,614	2,476,021
43	Notes Receivable from Associated Companies (145)		151,320	0
44	Accounts Receivable from Assoc. Companies (146)		11,231,843	15,718,807
45	Fuel Stock (151)	227	135,760,761	103,298,488
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	157,005,210	156,388,226
49	Merchandise (155)	227	259,681	204,989
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	9,611,855	10,253,426

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	9,156,997	19,516,453
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)		167,032,023	233,981,327
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		39,807	0
60	Rents Receivable (172)		341,514	282,642
61	Accrued Utility Revenues (173)		59,473,456	65,582,761
62	Miscellaneous Current and Accrued Assets (174)		0	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)		122,409,306	2,400,444
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		45,357,165	2,400,444
67	Total Current and Accrued Assets (Lines 34 through 66)		1,115,746,581	817,347,682
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		22,222,655	21,406,295
70	Extraordinary Property Losses (182.1)	230	206,801,434	12,645,771
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	495,698,128	350,394,489
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,845,394	0
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	30,456,477	365,126,350
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)		29,188,802	31,172,912
82	Accumulated Deferred Income Taxes (190)	234	201,057,047	167,278,404
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		987,269,937	948,024,221
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		7,665,324,074	6,949,473,358

Name 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	12/31/2005	end of 2005/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	742,267,894	726,881,210
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	1,497,932,244	1,239,735,201
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-111,569	-69,995
16	Total Proprietary Capital (lines 2 through 15)		2,628,021,699	2,354,479,546
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,870,865,000	1,570,865,000
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	738,800,005	391,800,002
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		6,194,270	3,111,251
24	Total Long-Term Debt (lines 18 through 23)		2,603,470,735	1,959,553,751
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		5,566,000	46,915,219
28	Accumulated Provision for Injuries and Damages (228.2)		20,887,409	13,023,633
29	Accumulated Provision for Pensions and Benefits (228.3)		172,905,984	161,692,198
30	Accumulated Miscellaneous Operating Provisions (228.4)		90,340,527	106,041,531
31	Accumulated Provision for Rate Refunds (229)		2,407,430	10,080,153
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		6,104,892	0
34	Asset Retirement Obligations (230)		289,505,643	336,645,620
35	Total Other Noncurrent Liabilities (lines 26 through 34)		587,717,885	674,398,354
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		102,000,000	292,867,000
38	Accounts Payable (232)		222,804,792	250,521,404
39	Notes Payable to Associated Companies (233)		12,726,233	178,777,135
40	Accounts Payable to Associated Companies (234)		100,825,190	79,500,854
41	Customer Deposits (235)		148,479,965	135,499,493
42	Taxes Accrued (236)	262-263	33,505,144	38,585,326
43	Interest Accrued (237)		41,703,816	45,838,009
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	12/31/2005	end of 2005/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)		14,308,056	11,230,317
48	Miscellaneous Current and Accrued Liabilities (242)		52,367,493	59,197,211
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		6,104,892	5,183,190
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		6,104,892	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		728,720,689	1,097,199,939
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	29,796,508	35,280,508
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	93,131,478	16,476,930
60	Other Regulatory Liabilities (254)	278	372,780,504	197,353,198
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	5,190,000	6,186,000
63	Accum. Deferred Income Taxes-Other Property (282)		438,183,791	435,312,618
64	Accum. Deferred Income Taxes-Other (283)		178,310,785	173,232,514
65	Total Deferred Credits (lines 56 through 64)		1,117,393,066	863,841,768
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		7,665,324,074	6,949,473,358

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	3,964,002,346	3,526,632,391		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,878,528,030	2,215,094,994		
5	Maintenance Expenses (402)	320-323	166,182,532	120,985,725		
6	Depreciation Expense (403)	336-337	269,678,438	263,999,924		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	373,504	1,494,018		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	13,963,292	16,809,016		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-411,097	-411,716		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		50,486,892			
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		105,728,403	228,228,437		
13	(Less) Regulatory Credits (407.4)		276,814,367	206,665,301		
14	Taxes Other Than Income Taxes (408.1)	262-263	278,509,732	254,104,999		
15	Income Taxes - Federal (409.1)	262-263	154,744,964	68,215,864		
16	- Other (409.1)	262-263	26,045,841	10,030,248		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	174,734,869	386,371,645		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	228,392,144	270,269,511		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,484,000	-6,071,000		
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)			-1,000		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		14,728,420	17,368,665		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,622,603,309	3,099,287,007		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		341,399,037	427,345,384		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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		Line No.
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)	
						1
3,964,002,346	3,526,632,391					2
						3
2,878,528,030	2,215,094,994					4
166,182,532	120,985,725					5
269,678,438	263,999,924					6
373,504	1,494,018					7
13,963,292	16,809,016					8
-411,097	-411,716					9
50,486,892						10
						11
105,728,403	228,228,437					12
276,814,367	206,665,301					13
278,509,732	254,104,999					14
154,744,964	68,215,864					15
26,045,841	10,030,248					16
174,734,869	386,371,645					17
228,392,144	270,269,511					18
-5,484,000	-6,071,000					19
						20
						21
	-1,000					22
						23
14,728,420	17,368,665					24
3,622,603,309	3,099,287,007					25
341,399,037	427,345,384					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	12/31/2005	End of 2005/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)		341,399,037	427,345,384		
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)		18,984,259	13,681,312		
34	(Less) Expenses of Nonutility Operations (417.1)		13,696,210	10,556,255		
35	Nonoperating Rental Income (418)		-364,108	-298,577		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		7,421,958	2,588,760		
38	Allowance for Other Funds Used During Construction (419.1)		13,228,664	7,100,379		
39	Miscellaneous Nonoperating Income (421)		332,370	1,639,090		
40	Gain on Disposition of Property (421.1)		25,554,411	1,450,090		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		51,461,344	15,604,799		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	5,893,387	4,269,120		
46	Life Insurance (426.2)		-2,123,063	-1,462,738		
47	Penalties (426.3)		4,350	97,191		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		3,730,611	4,221,840		
49	Other Deductions (426.5)		3,692,583	781,011		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		11,197,868	7,906,424		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	170,279	170,280		
53	Income Taxes-Federal (409.2)	262-263	-8,768,324	-13,002,964		
54	Income Taxes-Other (409.2)	262-263	-567,966	-981,567		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	19,216,000			
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	10,439,000			
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-389,011	-13,814,251		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		40,652,487	21,512,626		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		120,453,244	105,570,677		
63	Amort. of Debt Disc. and Expense (428)		3,416,045	3,186,615		
64	Amortization of Loss on Reaquired Debt (428.1)		2,158,945	2,113,865		
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	3,215,111	1,289,565		
68	Other Interest Expense (431)	340	5,129,913	5,277,422		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		8,474,818	3,462,518		
70	Net Interest Charges (Total of lines 62 thru 69)		125,898,440	113,975,626		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		256,153,084	334,882,384		
72	Extraordinary Items					
73	Extraordinary Income (434)		3,743,818			
74	(Less) Extraordinary Deductions (435)		187,999			
75	Net Extraordinary Items (Total of line 73 less line 74)		3,555,819			
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)		3,555,819			
78	Net Income (Total of line 71 and 77)		259,708,903	334,882,384		

Schedule Page: 114 Line No.: 10 Column: d

Balance as of December 31, 2004 was ($18,677,749). Increase of $18,677,749 is due to a reclassification to Regulatory Debits on line 12.

Schedule Page: 114 Line No.: 12 Column: d

Balance as of December 31, 2004 was $246,906,186. Decrease of $18,677,749 is due to reclassification to Amortization of Property Losses, Unrecoverable Plant and Regulatory Study Costs, Line 10.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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		1,239,735,201	1,061,364,677
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		259,708,903	334,882,384
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			(155,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			(155,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,497,932,244	1,239,735,201
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,497,932,244	1,239,735,201
	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)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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)	259,708,903	334,882,384
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	271,508,782	264,138,621
5	Amortization of Limited and Electric Plant, Nuclear Fuel, Load Mgmt	32,890,246	38,424,782
6	Amortization of Debt Premium, expense and loss on reacquisition	3,707,016	2,542,010
7	Other: (Gain) Loss on sale of assets, Other adjustments to Net Income	124,428,537	-7,200,047
8	Deferred Income Taxes (Net)	-44,880,275	116,102,135
9	Investment Tax Credit Adjustment (Net)	-5,484,000	-6,071,000
10	Net (Increase) Decrease in Receivables	-66,178,429	-29,023,770
11	Net (Increase) Decrease in Inventory	-35,879,902	-26,671,813
12	Net (Increase) Decrease in Allowances Inventory	639,822	-9,341,337
13	Net Increase (Decrease) in Payables and Accrued Expenses	72,517,361	47,896,994
14	Net (Increase) Decrease in Other Regulatory Assets	-155,804,627	46,098,547
15	Net Increase (Decrease) in Other Regulatory Liabilities	-27,415,354	-1,064,212
16	(Less) Allowance for Other Funds Used During Construction	13,228,664	7,100,379
17	(Less) Undistributed Earnings from Subsidiary Companies	-53,746	-40,184
18	Other (provide details in footnote): Change in current assets	-12,485,946	1,650,630
19	Change in Other, net	24,694,768	-231,929,255
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	428,791,984	533,374,474
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-487,488,299	-488,148,771
27	Gross Additions to Nuclear Fuel	-46,911,677	-417,550
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-677,975	-2,431,960
30	(Less) Allowance for Other Funds Used During Construction	8,474,818	3,462,518
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-543,552,769	-494,460,799
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	43,055,634	82,660
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-210,000	-210,000
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-404,961,139	-568,974,627
45	Proceeds from Sales of Investment Securities (a)	404,961,139	568,974,627

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	-4,834,334	-1,500,000
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-505,541,469	-496,088,139
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	744,279,609	56,053,296
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		292,867,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	744,279,609	348,920,296
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-102,999,998	-42,699,998
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote): Dividends paid to Parent		-155,000,000
77	Decrease in Intercompany Notes, Other	-165,752,932	-184,497,035
78	Net Decrease in Short-Term Debt (c)	-190,867,000	
79	Other	-1,297,477	
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)	281,850,343	-34,788,596
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	205,100,858	2,497,739
87			
88	Cash and Cash Equivalents at Beginning of Period	10,973,321	8,475,582
89			
90	Cash and Cash Equivalents at End of period	216,074,179	10,973,321

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2005	2005/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 4 Column:

Decrease of $1,494,018 versus prior year filing due to reclassification to line 5 (related to ARO amortization).

Schedule Page: 120 Line No.: 5 Column:

Increase of $1,494,018 versus prior year filing due to reclassification from Line 4 (related to amortization of ARO).

Schedule Page: 120 Line No.: 7 Column:

Decrease of $11,347,537 versus 12/31/04 (amount originally at 12/31/04 was $4,147,490) filing due to change in cash flow classification of pension credits and bad debt expense.

Schedule Page: 120 Line No.: 10 Column:

Decrease in cash used of $45,316 versus original 12/31/04 filing amount of ($29,069,086) due to classification of bad debt expense.

Schedule Page: 120 Line No.: 14 Column:

Increase of $18,733,149 versus original 12/31/04 filing amount of $27,365,398 is due to a change in cash flow classification related to the environmental accruals (offset of this change is in Change in Other, net.

Schedule Page: 120 Line No.: 19 Column:

Line 19 decreased $220,627,036 versus the original 12/31/04 filing. This is due to a cash flow classification change related to pension credits (offset of this change is Line 7) in the amount of $11,302,220. The amount on line 20 in the original 12/31/04 filing was ($213,196,107). This amount has decreased by $18,733,149 (due to change in cash flow classification related to environmental accruals) and has been moved to line 19 for the current year filing.

Schedule Page: 120 Line No.: 44 Column:

Decrease from original 12/31/04 filing of $568,974,627 due to change in presentation related to investments through the Nuclear Decommissioning Trust funds. Offset is on line 45.

Schedule Page: 120 Line No.: 45 Column:

See note at line 44.

NOTES TO FINANCIAL STATEMENTS

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

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

Florida Power Corp d/b/a/ Progress Energy Florida's (PEF) financial statements have been prepared in conformity with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. These requirements differ from generally accepted accounting principles related to (1) cost of removal of assets and liabilities, (2) storm costs, (3) deferred and accrued income taxes, (4) SFAS No. 109 regulatory assets and liabilities, (5) current portions of long-term debt, (6) reclassification of accrued pension from prepaid pension to long-term liabilities, (7) current and long-term portions of derivatives, (8) reclassification of acquisition adjustment to CWIP, (9) classification of gain on sale of distribution assets, (10) classification of the asset retirement obligation accretion expense to depreciation and amortization and (11) the reclassification of the rate refund accrual (as a result of the rate case) from a long-term liability to a current liability.

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

OTHER DISCLOSURE

Cash payments for interest and income taxes for 2005 were approximately $131 million and $185 million, respectively.

The expense associated with special assessments levied under the Atomic Energy Act of 1954 as amended by Title XI of the Energy Policy Act of 1993 and recorded in account 518 in 2005 was $1,849,912. The payment made in November 2005 for such special assessments totaled $2,047,871.

Allowance for Borrowed Funds Used During Construction is not included in Gross Additions to Utility Plant on line No. 26 of the Statement of Cash Flows. The amount included on line No. 30 of the Statement of Cash Flows represents the Allowance for Borrowed Funds Used During Construction.

PROGRESS ENERGY, INC.
CAROLINA POWER & LIGHT COMPANY d/b/a/ PROGRESS ENERGY CAROLINAS, INC.
FLORIDA POWER CORPORATION d/b/a/ PROGRESS ENERGY FLORIDA, INC.
COMBINED NOTES TO FINANCIAL STATEMENTS

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

Progress Energy, Inc.

The Parent is a holding company headquartered in Raleigh, N.C. Prior to February 8, 2006, the Parent was registered under the Public Utility Holding Company Act of 1935 (PUHCA), as amended. As such, we were subject to the regulatory provisions of PUHCA. Subsequent to February 8, 2006, the Parent is subject to additional regulation by the Federal Energy Regulatory Commission (FERC) as a result of legislation passed in 2005.

Our reportable segments are: PEC, PEF, Progress Ventures, and Coal and Synthetic Fuels. Our PEC and PEF segments are engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. Our Progress Ventures segment is involved in nonregulated electric generation and energy marketing activities and natural gas drilling and production. Our Coal and Synthetic Fuels segment is involved in the production and sale of coal-based solid synthetic fuel as defined under the Internal Revenue Code (the Code), coal terminal services, and fuel transportation and delivery. Through our other business units, we engage in other nonregulated business areas, including telecommunications, which are included in our Corporate and Other segment (Corporate and Other).

Our Rail Services operations were reclassified to discontinued operations in the first quarter of 2005 (See Note 3B). During the fourth quarter of 2005, our coal mining operations were reclassified to discontinued operations (See Note 3A). Our Rail Services and coal mining operations are not included in the results from continuing operations during the periods reported.

During 2005, we realigned our segments based on the manner in which management currently reviews these operations. Prior year periods have been restated for our segment realignments. See Note 20 for further information about our segments.

PEC

PEC is a public service corporation 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), the Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC), the FERC as well as the provisions of PUHCA prior to February 8, 2006 due to PEC being a wholly owned subsidiary of Progress Energy.

PEF

PEF is a public service corporation 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, the FERC as well as the provisions of PUHCA prior to February 8, 2006 due to PEF being a wholly owned subsidiary of Progress Energy.

B. Basis of Presentation

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

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies (generally 20 to 50 percent ownership), are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 21). Other investments are stated principally at cost. These equity and cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. See Note 13 for more information about our investments.

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

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

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

Certain amounts for 2004 and 2003 have been reclassified to conform to the 2005 presentation.

C. Consolidation of Variable Interest Entities

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

Progress Energy

In addition to the variable interests listed below for PEC and PEF, we have interests through other subsidiaries in variable interest entities for which we are not the primary beneficiary. These arrangements include investments in five limited liability partnerships and limited liability corporations. At December 31, 2005, the aggregate additional maximum loss exposure that we could be required to record in our income statement as a result of these arrangements was approximately $8 million, which represents our net remaining investment in these entities. The creditors of these variable interest entities do not have recourse to our general credit in excess of the aggregate maximum loss exposure.

PEC

PEC is the primary beneficiary of and consolidates two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Code. At December 31, 2005, the total assets of the two entities were $38 million, the majority of which are collateral for the entities' obligations and are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

PEC has an interest in and consolidates a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. PEC has requested the necessary information to determine if the 17 partnerships are variable interest entities or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC and PEC has applied the information scope exception in FIN No. 46R, paragraph 4(g), to the 17 partnerships. PEC has no direct exposure to loss from the 17 partnerships; PEC's only exposure to loss is from its investment of less than $1 million in the consolidated limited partnership. PEC will continue its efforts to obtain the necessary information to fully apply FIN No. 46R to the 17 partnerships. PEC believes that if the limited partnership is determined to be the primary beneficiary of the 17 partnerships, the effect of consolidating the 17 partnerships would not be significant to PEC's Consolidated Balance Sheets.

PEC also has an interest in one power plant resulting from long-term power purchase contracts. Our only significant exposure to variability from these contracts results from fluctuations in the market price of fuel used by the entity's plants to produce the power purchased by PEC. We are able to recover these fuel costs under PEC's fuel clause. Total purchases from this counterparty were approximately $44 million, $42 million and $37 million in 2005, 2004 and 2003, respectively. The generation capacity of the entity's power plant is approximately 835 MW. PEC has requested the necessary information to determine if the power plant owner is a variable interest entity or to identify the primary beneficiary. The entity declined to provide us with the necessary financial information and PEC has applied the information scope exception in FIN No. 46R, paragraph 4(g), to the power plant. PEC believes that if it is determined to be the primary beneficiary of the entity, the effect of consolidating the entity would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparty, the impact cannot be determined at this time.

PEC also has interests in several other variable interest entities for which PEC is not the primary beneficiary. These arrangements include investments in approximately 22 limited liability partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. At December 31, 2005, the aggregate maximum loss exposure that PEC could be required to record in its income statement as a result of these arrangements totals approximately $23 million, which primarily represents our net remaining investment in these entities. The creditors of these variable interest entities do not have recourse to the general credit of PEC in excess of the aggregate maximum loss exposure.

PEF

PEF has interests in three variable interest entities for which PEF is not the primary beneficiary. These arrangements include investments in one limited liability corporation, one venture capital fund and one building lease with a special-purpose entity. At December 31, 2005, the aggregate maximum loss exposure that PEF could be required to record in its income statement as a result of these arrangements was approximately $1 million. The creditors of these variable interest entities do not have recourse to the general credit of PEF in excess of the aggregate maximum loss exposure.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

We recognize revenue when it is realized or realizable and earned when all of the following criteria are met: persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; our price to the buyer is fixed or determinable; and collectability is reasonably assured. We recognize electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utility revenues earned when service has been delivered but not billed by the end of the accounting period. Diversified business revenues are generally recognized at the time products are shipped or as services are rendered. Leasing activities are accounted for in accordance with SFAS No. 13, "Accounting for Leases." Revenues related to design and construction of wireless infrastructure are recognized upon completion of services for each completed phase of design and construction. Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. Customer prepayments are recorded as deferred revenue and recognized as revenues as the services are provided.

FUEL COST DEFERRALS

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

EXCISE TAXES

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

(in millions)	**2005**	2004	2003
Progress Energy	**$ 258**	$ 240	$ 217
PEC	**91**	89	81
PEF	**167**	151	136

STOCK-BASED COMPENSATION

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

RELATED PARTY TRANSACTIONS

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of the PUHCA. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. In the subsidiaries' financial statements, billings from affiliates are capitalized or expensed depending on the nature of the services rendered. The repeal of PUHCA effective February 8, 2006, and subsequent regulation by the FERC is not anticipated to change our current intercompany services.

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs of units of property as well as indirect construction costs. Certain costs that would otherwise not be capitalized under GAAP are capitalized in accordance with regulatory treatment. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property (including planned major maintenance activities), and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred, with the exception of nuclear outages at PEF. Pursuant to a regulatory order, PEF accrues for nuclear outage costs in advance of scheduled outages, which occur every two years. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal or disposal costs that do not represent asset retirement obligations under SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), are charged to a regulatory liability.

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

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, we adopted the guidance in SFAS No. 143 to account for legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. As discussed in Note 2, effective December 31, 2005, we also adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN No. 47), which clarified certain requirements of SFAS No. 143.

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

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

For financial reporting purposes, substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 5A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization of utility assets (See Note 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.

CASH AND CASH EQUIVALENTS

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

INVENTORY

We account for inventory, including emission allowances, using the average cost method. Inventories are valued at the lower of average cost or market.

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to SFAS No. 71, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, the Utilities record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 7A). The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

DIVERSIFIED BUSINESS PROPERTY

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

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

GOODWILL AND INTANGIBLE ASSETS

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

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

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

INCOME TAXES

We and our affiliates file a consolidated federal income tax return. The consolidated income tax of Progress Energy is allocated to PEC and PEF in accordance with the Intercompany Income Tax Allocation Agreement (Tax Agreement). The Tax Agreement provides an allocation that recognizes positive and negative corporate taxable income. The Tax Agreement provides for an equitable method of apportioning the carryover of uncompensated tax benefits, which primarily relate to deferred synthetic fuel tax credits. Since 2002, Progress Energy tax benefits not related to acquisition interest expense have been allocated to profitable subsidiaries in accordance with a PUHCA order. Except for the allocation of these Progress Energy tax benefits, income taxes are provided as if PEC and PEF filed separate returns. Due to the repeal of PUHCA, effective February 8, 2006, we will stop allocating these tax benefits.

Deferred income taxes have been provided for temporary differences. These occur when there are differences between the book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. Credits for the production and sale of synthetic fuel are deferred as alternative minimum tax credits to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns, and are included in income tax expense (benefit) in the Consolidated Statements of Income. Interest expense on tax deficiencies is included in net interest charges 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" (SFAS No. 138), and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as assets or liabilities in the balance sheet and measure those instruments at fair value, unless the derivatives meet the SFAS No. 133 criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the SFAS No. 133 criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related SFAS No. 133 hedge criteria are met. During 2003, the FASB reconsidered an interpretation of SFAS No. 133. See Note 18 for the effect of the interpretation and additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

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

As discussed in Note 22, we accrue environmental remediation liabilities when the criteria for SFAS No. 5 have been met. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

As discussed in Note 9, we account for impairment of long-lived assets in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). We review the recoverability of long-lived tangible and intangible assets whenever indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

We review our investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. We consider various factors, such as the investee's cash position, earnings and revenue outlook, liquidity and management's ability to raise capital in determining whether the decline is other-than-temporary. If we determine that an other-than-temporary decline exists in the value of its investments, it is our policy to write-down these investments to fair value.

Under the full-cost method of accounting for oil and gas properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. The ceiling test takes into consideration the prices of qualifying cash flow hedges as of the balance sheet date. If the ceiling (discounted revenues) is not equal to or greater than total capitalized costs, we are required to write-down capitalized costs to this level. We perform this ceiling test calculation every quarter. No write-downs were required in 2005, 2004 or 2003.

SUBSIDIARY STOCK TRANSACTIONS

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

2. NEW ACCOUNTING STANDARDS

See Note 10B for information regarding our third quarter 2005 implementation of SFAS No. 123R.

FASB EXPOSURE DRAFT ON ACCOUNTING FOR UNCERTAIN TAX POSITIONS, AN INTERPRETATION OF SFAS NO. 109, "ACCOUNTING FOR INCOME TAXES"

On July 14, 2005, the FASB issued an exposure draft of a proposed interpretation of SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109), that would address the accounting for uncertain tax positions. The proposed interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the consolidated financial statements. We currently account for uncertain tax benefits in accordance with SFAS No. 5. Under SFAS No. 5, contingent losses are recorded when it is probable that the tax position will not be sustained and the amount of the disallowance can be reasonably estimated. During subsequent deliberations in November 2005, the FASB voted to tentatively adopt a more-likely-than-not criterion that the uncertain tax position will be sustained rather than the original probable criterion. As originally drafted, the proposed interpretation would apply to all uncertain tax positions and would have been effective for us on December 31, 2005. However, on January 11, 2006, the FASB voted to delay the effective date of the final interpretation until the first annual period beginning after December 15, 2006, which for us would be January 1, 2007. The FASB has publicly stated that it expects to issue the final interpretation in the first quarter of 2006. We have not yet determined how the proposed interpretation would impact our various income tax positions.

FASB INTERPRETATION NO. 47, "ACCOUNTING FOR CONDITIONAL ASSET RETIREMENT OBLIGATIONS"

As discussed in Note 1D, we adopted FIN No. 47, an interpretation of SFAS No. 143, as of December 31, 2005. FIN No. 47 clarifies that a legal obligation to perform an asset retirement activity that is conditional on a future event is within the scope of SFAS No. 143. Accordingly, an entity is required to recognize a liability for the fair value of an asset retirement obligation (ARO) that is conditional on a future event if the liability's fair value can be reasonably estimated. FIN No. 47 also provides additional guidance for evaluating whether sufficient information is available to make a reasonable estimate of the fair value.

Upon implementation of FIN No. 47 we recognized additional ARO liabilities for asbestos abatement costs. In accordance with SFAS No. 143, we recorded a liability for the present value of our legal obligations and recorded an additional amount to the asset cost to be depreciated over an appropriate period. Cumulative accretion and accumulated depreciation were recognized for the time period from the date of the obligating event giving rise to the liability to the date of the adoption of FIN No. 47. For assets acquired through acquisition, the cumulative effect was based on the acquisition date. As stated in Note 1D, the adoption of FIN No. 47 had no impact on the income of the Utilities as the effects were offset by the establishment of a net regulatory asset/liability pursuant to SFAS No. 71 (See Note 7A) and in accordance with orders issued by the NCUC, the SCPSC and the FPSC.

The following table summarizes the effect of the implementation of FIN No. 47 on the financial statements of Progress Energy, PEC and PEF as of December 31, 2005.

(in millions)	ARO Liability	Net Asset Retirement Cost	Net Regulatory Asset/(Liability)
Progress Energy	$ 50	$ 15	$ (8)
PEC	23	5	2
PEF	27	4	(4)

Asbestos abatement costs previously included in regulatory liabilities were reclassified upon implementation of FIN No. 47 and included in the calculation of these AROs at December 31, 2005. The amounts reclassified were $16 million and $27 million for PEC and PEF, respectively, for a cumulative total of $43 million for Progress Energy.

3. DIVESTITURES

A. Coal Mines Divestiture

On November 14, 2005, our board of directors approved a plan to divest of five subsidiaries of Progress Fuels Corporation (Progress Fuels) engaged in the coal mining business. The coal mining operations are expected to be sold by the end of 2006. As a result, the accompanying consolidated financial statements have been restated for all periods presented to reflect the coal mining operations as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of the coal mines, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated was $3 million for each of the years ended December 31, 2005, 2004 and 2003. We ceased recording depreciation expense upon classification of the coal mining operations as discontinued operations in November 2005. After-tax depreciation expense during the years ended December 31, 2005, 2004 and 2003 was $10 million, $9 million and $9 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	**2005**	2004	2003
Revenues	**$180**	$ 158	$ 181
Loss before income taxes	**$ 16**	$ 17	$ 18
Income tax benefit	**5**	12	7
Net loss from discontinued operations	**$ 11**	$ 5	$ 11

B. Progress Rail Divestiture

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

Based on the gross proceeds associated with the sale of $429 million, we recorded an estimated after-tax loss on disposal of $25 million during the year ended December 31, 2005.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of Progress Rail as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of Progress Rail, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended December 31, 2005, 2004 and 2003 was $4 million, $16 million and $18 million, respectively. We ceased recording depreciation upon classification of Progress Rail as discontinued operations in February 2005. After-tax depreciation expense during the years ended December 31, 2005, 2004 and 2003 was $3 million, $10 million and $9 million, respectively. Results of discontinued operations for the years ended

December 31 were as follows:

(in millions)	**2005**	2004	2003
Revenues	**$ 358**	$ 1,127	$ 847
Earnings before income taxes	**$ 8**	$ 50	$ 23
Income tax expense	**3**	21	9
Net earnings from discontinued operations	**5**	29	14
Estimated loss on disposal of discontinued operations, including income tax benefit of $15 in 2005	**(25)**	–	–
(Loss) earnings from discontinued operations	**$ (20)**	$ 29	$ 14

In connection with the sale, Progress Fuels and Progress Energy provided guarantees and indemnifications of certain legal, tax and environmental matters to One Equity Partners, LLC. See Note 23C for a general discussion of guarantees. The ultimate resolution of these matters could result in adjustments to the loss on sale in future periods.

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

C. Net Assets of Discontinued Operations

Included in net assets of discontinued operations are the assets and liabilities of the coal mining operations and Progress Rail. The major balance sheet classes included in assets and liabilities of discontinued operations in the Consolidated Balance Sheet at December 31, 2005 and 2004 were as follows:

(in millions)	**2005**	2004
Accounts receivable	**$ 12**	$ 189
Inventory	**6**	181
Other current assets	**4**	19
Total property, plant and equipment, net	**73**	240
Total other assets	**14**	56
Assets of discontinued operations	**$ 109**	$ 685
Accounts payable	**$ 9**	$ 119
Other current liabilities	**11**	47
Long-term liabilities	**20**	20
Liabilities of discontinued operations	**$ 40**	$ 186

D. Divestiture of Winter Park Distribution Assets

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

E. Sale of Natural Gas Assets

In December 2004, we sold certain gas-producing properties and related assets owned by Winchester Production Company, Ltd. (Winchester Production), an indirectly wholly owned subsidiary of Progress Fuels, which is included in the Progress Ventures segment. Net proceeds of approximately $251 million were used to reduce debt. Because the sale significantly altered the ongoing relationship between capitalized costs and remaining proved reserves, under the full-cost method of accounting, the pre-tax gain of $56 million was recognized in earnings rather than as a reduction of the basis of our remaining oil and gas properties. The pre-tax gain has been included in (gain)/loss on the sale of assets in the Consolidated Statements of Income.

F. Divestiture of Synthetic Fuel 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 fuel facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gain from the sales will be recognized on a cost-recovery basis. The book value of the interests sold totaled approximately $5 million. In the event that the synthetic fuel tax credits from the Colona facility are reduced, including an increase in the price of oil that could limit or eliminate synthetic fuel tax credits, the amount of proceeds realized from the sale could be significantly impacted (See Note 23D).

G. Mesa Hydrocarbons, Inc., Divestiture

In October 2003, we sold certain gas-producing properties owned by Mesa Hydrocarbons, LLC, a wholly owned subsidiary of Progress Fuels. Net proceeds were approximately $97 million. Because we utilize the full-cost method of accounting for our oil and gas operations, the pre-tax gain of approximately $18 million was applied to reduce the basis of our other U.S. oil and gas investments and will prospectively result in a reduction of the amortization rate applied to those investments as production occurs.

H. NCNG Divestiture

On September 30, 2003, we sold North Carolina Natural Gas Corporation (NCNG) and our equity investment in Eastern North Carolina Natural Gas Company (ENCNG) to Piedmont Natural Gas Company, Inc. Net proceeds from the sale of NCNG of approximately $443 million were used to reduce debt.

The consolidated financial statements have been restated for all periods presented for the discontinued operations of NCNG. The net income of these operations is reported as discontinued operations in the Consolidated Statements of Income. Interest expense of $10 million for the year ended December 31, 2003, has been allocated to discontinued operations based on the net assets of NCNG, assuming a uniform debt-to-equity ratio across our operations. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	2004	2003
Revenues	$ –	$ 284
Earnings before income taxes	$ –	$ 6
Income tax expense	–	2
Net earnings from discontinued operations	–	4
Gain/(Loss) on disposal of discontinued operations, including applicable income tax benefit / (expense) of $6 and $1, respectively	6	(12)
Earnings (loss) from discontinued operations	$ 6	$ (8)

NCNG did not have any discontinued operating results for the year ended December 31, 2005.

During 2004, we recorded an additional tax gain of approximately $6 million due to final tax adjustments related to the divestiture of NCNG.

The sale of ENCNG resulted in net proceeds of $7 million and a pre-tax loss of $2 million, which is included in other, net on the Consolidated Statements of Income for the year ended December 31, 2003.

4. ACQUISITIONS AND BUSINESS COMBINATIONS

A. Acquisition of Natural Gas Reserves - 2005

In May 2005, Winchester Production, an indirectly wholly owned subsidiary of Progress Fuels, acquired a 50 percent interest in approximately 11 natural gas producing wells and proven reserves of approximately 25 billion cubic feet equivalent (Bcf) from a privately owned company headquartered in Texas. In addition to the natural gas reserves, the transaction also included a 50 percent interest in the gas gathering systems related to these reserves. The total cash purchase price for the transaction was $46 million. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2005, 2004 or 2003.

B. Progress Telecommunications Corporation Transaction

In December 2003, Progress Telecommunications Corporation (PTC) and Caronet, Inc. (Caronet), both wholly owned subsidiaries of Progress Energy, and EPIK Communications, Inc. (EPIK), a wholly owned subsidiary of Odyssey Telecorp, Inc. (Odyssey), contributed substantially all of their assets and transferred certain liabilities to Progress Telecom, LLC (PT LLC), a subsidiary of PTC as a noncash activity that is not reflected on our consolidated statements of cash flows. Subsequently, the stock of Caronet was sold to an affiliate of Odyssey for $2 million in cash and Caronet became a wholly owned subsidiary of Odyssey. Following consummation of all the transactions described above, PTC held a 55 percent ownership interest in, and is the parent of, PT LLC. Odyssey held a combined 45 percent ownership interest in PT LLC through EPIK and Caronet. The accounts of PT LLC have been included in the Consolidated Financial Statements since the transaction date.

The transaction was accounted for as a partial acquisition of EPIK through the issuance of the stock of a consolidated subsidiary. The contributions of PTC's and Caronet's net assets were recorded at their carrying values of approximately $31 million. EPIK's contribution was recorded at its estimated fair value of $22 million using the purchase method. No gain or loss was recognized on the transaction. The EPIK purchase price was initially allocated as follows: property and equipment – $27 million; other current assets – $9 million; current liabilities – $21 million; and goodwill – $7 million. During 2004, PT LLC developed a restructuring plan to exit certain leasing arrangements of EPIK and finalized its valuation of acquired assets and liabilities. Management considered a number of factors, including valuations and appraisals, when making these determinations. Based on the results of these activities, the preliminary purchase price allocation for EPIK was revised as follows at December 31, 2004: property and equipment – $36 million; other current assets – $7 million; intangible assets – $1 million; current liabilities – $18 million; and exit costs – $4 million. The exit costs consist primarily of lease termination penalties and noncancelable lease payments made after certain leased properties are vacated. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2003.

See Note 25 for information on the recent agreement to sell our interest in PT LLC.

C. Acquisition of Natural Gas Reserves - 2003

During 2003, Progress Fuels entered into several independent transactions to acquire approximately 200 natural gas-producing wells with proven reserves of approximately 190 Bcf from Republic Energy, Inc., and three other privately owned companies, all headquartered in Texas. The total cash purchase price for the transactions was $168 million. The pro forma results of operations reflecting the acquisition would not be materially different from the reported results of operations for the year ended December 31, 2003.

D. Acquisition of Wholesale Energy Contract

In May 2003, Progress Energy Ventures, Inc. (PVI) entered into a definitive agreement with Williams Energy Marketing and Trading, a subsidiary of The Williams Companies, Inc., to acquire a long-term full-requirements power supply agreement at fixed prices with Jackson Electric Membership Corporation (Jackson), located in Jefferson, Georgia. The agreement required a $188 million cash payment to Williams Energy Marketing and Trading in exchange for assignment of the Jackson supply agreement; the $188 million cash payment was recorded as an intangible asset and is being amortized based on the economic benefit of the contract (See Note 8). The power supply agreement terminates in 2015, with a first refusal right to extend for five years. The agreement includes the use of 640 MW of contracted Georgia System generation comprised of nuclear, coal, gas and pumped-storage hydro resources. PVI expects to supplement the acquired resources with open market purchases and with its own intermediate and peaking assets in Georgia to serve Jackson's forecasted 1,100 MW peak demand in 2005 growing to a forecasted 1,700 MW demand by 2015.

5. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

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

	Depreciable	Progress Energy		PEC		PEF	
(in millions)	Lives	**2005**	2004	**2005**	2004	**2005**	2004
Production plant	7-33	**$ 12,470**	$ 11,966	**$ 8,241**	$ 7,954	**$ 4,039**	$ 3,818
Transmission plant	30-75	**2,353**	2,282	**1,264**	1,212	**1,089**	1,070
Distribution plant	12-50	**7,015**	6,749	**3,838**	3,701	**3,177**	3,047
General plant and other	8-75	**1,102**	1,106	**651**	654	**451**	452
Utility plant in service		**$ 22,940**	$ 22,103	**$ 13,994**	$ 13,521	**$ 8,756**	$ 8,387

Generally, electric utility plant at PEC and PEF, other than nuclear fuel, is pledged as collateral for the first mortgage bonds of PEC and PEF, respectively (See Note 12C).

AFUDC represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 5.6% in 2005, 7.2% in 2004 and 4.0% in 2003, respectively. The composite AFUDC rate for PEF's electric utility plant was 7.8% in 2005, 2004 and 2003.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.5%, 2.2% and 2.5% in 2005, 2004 and 2003, respectively. The depreciation provisions related to utility plant were $556 million, $463 million and $517 million in 2005, 2004 and 2003, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Notes 7 and 22) and Clean Smokestacks Act amortization (See Note 7B).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2005 and 2004 were $140 million and for the year ended December 31, 2003 was $143 million. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income.

PEC's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.7% in 2005, 2.1% in 2004, and 2.7% in 2003. The depreciation provisions related to utility plant were $365 million, $275 million and $345 million in 2005, 2004 and 2003, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Note 7) and Clean Smokestacks Act amortization (See Note 7B).

During 2004, PEC met the requirements of both the NCUC and the SCPSC for the implementation of two depreciation studies that allowed the utility to reduce the rates used to calculate depreciation expense. The annual reduction in depreciation expense is approximately $82 million. The reduction is due primarily to extended lives at each of PEC's nuclear units. The reduced depreciation rates were effective January 1, 2004.

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.3% in 2005, 2004 and 2003. The depreciation provisions related to utility plant were $191 million, $188 million and $172 million in 2005, 2004 and 2003, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D) and regulatory approved expenses (See Notes 7 and 22).

During 2005, PEF performed a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study will decrease the rates used to calculate depreciation expense with a resulting decrease in annual depreciation expense of $26 million beginning in 2006 (See Note 7C).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the DOE and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2005, 2004 and 2003 was $109 million, $106 million and $112 million, respectively, for PEC and $31 million, $34 million and $31 million, respectively, for PEF. These costs were included in fuel used for electric generation in the Statements of Income.

B. Diversified Business Property

Progress Energy

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

(in millions)	**2005**	2004
Equipment (3-25 years)	**$ 146**	$ 129
Nonregulated generation plant and equipment (3-40 years)	**1,330**	1,302
Land and mineral rights	**40**	36
Buildings and plants (5-40 years)	**70**	70
Oil and gas properties (units-of-production)	**493**	334
Telecommunications equipment (5-20 years)	**99**	80
Rail equipment (3-20 years)	**37**	36
Marine equipment (3-35 years)	**88**	87
Computers, office equipment and software (3-10 years)	**8**	13
Construction work in progress	**12**	18
Accumulated depreciation	**(443)**	(332)
Diversified business property, net	**$ 1,880**	$ 1,773

Our nonregulated businesses capitalize interest costs under SFAS No. 34, "Capitalization of Interest Costs." During the years ended December 31, 2005, 2004 and 2003, respectively, we capitalized \$4 million, \$7 million and \$20 million, respectively, of our interest cost of \$656 million, \$641 million and \$634 million, respectively. Capitalized interest for 2005 and 2004 is related to the expansion of natural gas operations. Capitalized interest in 2003 is related to the expansion of the Progress Ventures nonregulated generation portfolio. Capitalized interest is included in diversified business property, net on the Consolidated Balance Sheets. Diversified business depreciation expense was \$116 million for December 31, 2005 and 2004 and \$91 million for December 31, 2003.

PEC

Net diversified business property was \$7 million at both December 31, 2005 and 2004. These amounts consist primarily of buildings and equipment that are being depreciated over periods ranging from 10 to 40 years. Accumulated depreciation was \$2 million at both December 31, 2005 and 2004. Diversified business depreciation expense was less than \$1 million in both 2005 and 2004 and \$1 million in 2003. Net diversified business property is included in miscellaneous other property and investments on the Consolidated Balance Sheets.

C. Joint Ownership of Generating Facilities

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs (See Note 22B). PEC's and PEF's share of expenses for the jointly owned facilities is included in the appropriate expense category. The co-owner of Intercession City Unit P11 (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:

2005 (in millions) Subsidiary	**Facility**	**Company Ownership Interest**	**Plant Investment**	**Accumulated Depreciation**	**Construction Work in Progress**
PEC	**Mayo**	**83.83%**	**\$ 518**	**\$ 255**	**\$ 1**
PEC	**Harris**	**83.83%**	**3,181**	**1,459**	**17**
PEC	**Brunswick**	**81.67%**	**1,614**	**921**	**23**
PEC	**Roxboro Unit 4**	**87.06%**	**355**	**153**	**10**
PEF	**Crystal River Unit 3**	**91.78%**	**808**	**493**	**48**
PEF	**Intercession City Unit P11**	**66.67%**	**24**	**4**	**–**

2004 (in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	\$ 516	\$ 249	\$ 1
PEC	Harris	83.83%	3,185	1,387	13
PEC	Brunswick	81.67%	1,624	888	28
PEC	Roxboro Unit 4	87.06%	323	147	1
PEF	Crystal River Unit 3	91.78%	889	443	9
PEF	Intercession City Unit P11	66.67%	22	7	8

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, 2005 and 2004, the asset retirement costs related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $31 million and $46 million, respectively, for PEC and $36 million at December 31, 2004 for PEF. No costs related to nuclear decommissioning of irradiated plant were recorded in 2005 at PEF. At December 31, 2005 and 2004, additional PEF-related asset retirement costs, net of accumulated depreciation, of $137 million and $193 million, respectively, were recorded at Progress Energy. Funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $640 million and $580 million at December 31, 2005 and 2004, respectively, for PEC and $493 million and $464 million, respectively, for PEF. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 7A).

PEC's decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million in 2005, 2004 and 2003. Management believes that decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 asset retirement obligations, which are included in depreciation and amortization expense, were $90 million, $83 million and $86 million in 2005, 2004 and 2003, respectively, for PEC and $78 million, $77 million and $72 million in 2005, 2004 and 2003, respectively, for PEF.

The Utilities recognize removal, nonirradiated decommissioning and dismantlement of fossil generation plants 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)	**2005**	2004	**2005**	2004	**2005**	2004
Removal costs	**$ 1,316**	$ 1,606	**$ 661**	$ 601	**$ 655**	$ 1,005
Nonirradiated decommissioning costs	**132**	131	**71**	70	**61**	61
Dismantlement costs	**123**	144	**–**	–	**123**	144
Non-ARO cost of removal	**$ 1,571**	$ 1,881	**$ 732**	$ 671	**$ 839**	$ 1,210

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 23D). These estimates, in 2004 dollars, were $569 million for Unit No. 2 at Robinson Nuclear Plant (Robinson), $418 million for 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 December 2014 and September 2016 for Brunswick Units No. 2 and No. 1, respectively. An application to extend these licenses 20 years was submitted in October 2004. The NRC operating license held by PEC for Harris currently expires in October 2026. An application to extend this license 20 years is expected to be submitted in the fourth quarter of 2006. On April 19, 2004, the NRC announced that it renewed the operating license for Robinson for an additional 20 years through July 2030.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF filed a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) with the FPSC on April 29, 2005, as part of PEF's base rate filing. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 23D). The estimate, in 2005 dollars, is $614 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. An application to extend this license 20 years is expected to be submitted in the first quarter of 2009. As part of this new estimate and assumed license extension, PEF reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $36 million and $88 million, respectively. In addition, we reduced PEF-related asset retirement costs, net of accumulated depreciation, by an additional $53 million at Progress Energy. Retail and wholesale accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of the Agreement and the new Base Rate Settlement continues that suspension.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF filed an updated fossil dismantlement study with the FPSC on April 29, 2005, as part of its base rate filing. The new study called for an increase in the annual accrual of $10 million beginning in 2006. PEF's reserve for fossil plant dismantlement was approximately $145 million at December 31, 2005, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended through December 2005 under the terms of PEF's existing Agreement. The Base Rate Settlement continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants (See Note 7C).

Upon implementation of FIN No. 47 as of December 31, 2005, the Utilities recognized additional ARO liabilities for asbestos abatement costs (See Note 2).

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

Our nonregulated AROs relate to the synthetic fuel operations and gas production of Progress Fuels. The related asset retirement costs, net of accumulated depreciation, totaled $10 million and $4 million at December 31, 2005 and 2004, respectively.

The following table shows the changes to the AROs during the years ended December 31. Additions relate primarily to additional reclamation obligations at coal mine operations of Progress Fuels and asbestos abatement at the Utilities. Revisions to prior estimates of the regulated ARO related to PEC remeasuring the nuclear decommissioning costs of irradiated plants to take into account updated site-specific decommissioning cost studies, which are required by the NCUC every five years. Revisions to prior estimates of the PEF regulated ARO are related to the updated cost estimate for nuclear decommissioning described above.

	Progress Energy			
(in millions)	Regulated	Nonregulated	PEC	PEF
Asset retirement obligations at January 1, 2004	$ 1,251	$ 5	$ 932	$ 319
Additions	–	1	–	–
Accretion expense	73	–	55	18
Revisions to prior estimates	(63)	(2)	(63)	–
Asset retirement obligations at December 31, 2004	1,261	4	924	337
Additions	**50**	**6**	**23**	**27**
Accretion expense	**65**	–	**51**	**14**
Revisions to prior estimates	**(137)**	–	**(49)**	**(88)**
Asset retirement obligations at December 31, 2005	**$ 1,239**	**$ 10**	**$ 949**	**$ 290**

The cumulative effect of initial adoption of SFAS No. 143 related to nonregulated operations was $1 million of income, which is included in cumulative effect of change in accounting principles, net of tax on the Consolidated Statements of Income for the year ended December 31, 2003.

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 $1.75 billion on each nuclear plant.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under NEIL, following a 12-week deductible period, for 52 weeks in the amount of $3.5 million per week at each plant. An additional 110 weeks of coverage is provided at 80 percent of the above weekly amount. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $30.7 million with respect to the primary coverage, $36.5 million with respect to the decontamination, decommissioning and excess property coverage, and $23 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $10.76 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from an insured nuclear incident exceed $300 million (currently available through commercial insurers), each company would be subject to pro rata assessments of up to $100.1 million for each reactor owned per occurrence. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $15 million per reactor owned.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.2 billion, along with any amounts it recovers from reinsurance, government indemnity or other sources up to the limits for each claimant. If terrorism losses occurred beyond the one-year period, a new set of limits and resources would apply. For nuclear liability claims arising out of terrorist acts, the primary level available through commercial insurers is now subject to an industry aggregate limit of $300 million. The second level of coverage obtained through the assessments discussed above would continue to apply to losses exceeding $300 million and would provide coverage in excess of any diminished primary limits due to terrorist acts.

The Utilities self-insure their transmission and distribution lines against loss due to storm damage and other natural disasters. PEF accrues $6 million annually to a storm damage reserve pursuant to a regulatory order and may defer losses in excess of the reserve (See Note 7A).

6. CURRENT ASSETS

A. Receivables

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

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Trade accounts receivable	**$ 713**	$ 499	**$ 336**	$ 240	**$ 263**	$ 195
Unbilled accounts receivable	**282**	271	**158**	155	**60**	66
Notes receivable	**76**	97	**–**	–	**–**	–
Other receivables	**45**	23	**28**	12	**14**	7
Unbilled other receivables	**6**	28	**–**	–	**–**	–
Allowance for doubtful accounts receivable	**(19)**	(22)	**(4)**	(10)	**(6)**	(2)
Total receivables	**$ 1,103**	$ 896	**$ 518**	$ 397	**$ 331**	$ 266

B. Inventory

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Fuel for production	**$ 329**	$ 235	**$ 185**	$ 127	**$ 136**	$ 104
Inventory for sale	**61**	49	**–**	–	**–**	–
Materials and supplies	**441**	517	**240**	263	**166**	176
Emission allowances	**35**	21	**26**	11	**9**	10
Total current inventory	**$ 866**	$ 822	**$ 451**	$ 401	**$ 311**	$ 290

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits for Progress Energy and PEC of $44 million at December 31, 2005 and none at December 31, 2004.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits for Progress Energy, PEC and PEF of $14 million, $13 million, and $1 million, respectively, at December 31, 2005 and none at December 31, 2004.

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 may 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, these factors could result in an impairment of utility plant assets as determined pursuant to SFAS No. 144.

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

Progress Energy

(in millions)	2005	2004
Deferred fuel cost – current (Notes 7B and 7C)	$ 602	$ 229
Deferred fuel cost – long-term (Notes 7B and 7C)	31	107
Deferred impact of ARO – PEC (Note 1D)	281	305
Income taxes recoverable through future rates (Note 14)	81	84
Loss on reacquired debt (Note 1D)	50	53
Storm deferral (Notes 7B and 7C)	227	316
Postretirement benefits (Note 16B)	88	74
Other	96	125
Total long-term regulatory assets	854	1,064
Deferred energy conservation cost – current	(10)	(8)
Non-ARO cost of removal (Note 5D)	(1,571)	(1,881)
Deferred impact of ARO – PEF (Note 1D)	(225)	(221)
Net nuclear decommissioning trust unrealized gains (Note 5D)	(251)	(224)
Postretirement benefits (Note 16B)	–	(45)
Clean Smokestacks Act compliance (Note 7B)	(317)	(248)
Derivative mark-to-market adjustment (Note 18A)	(122)	(2)
Other	(41)	(33)
Total long-term regulatory liabilities	(2,527)	(2,654)
Net regulatory liabilities	$ (1,081)	$ (1,369)

PEC

(in millions)	2005	2004
Deferred fuel cost – current (Note 7B)	$ 261	$ 140
Deferred fuel cost – long-term (Note 7B)	31	28
Deferred impact of ARO (Note 1D)	281	305
Income taxes recoverable through future rates (Note 14)	22	36
Loss on reacquired debt (Note 1D)	21	22
Storm deferral (Note 7B)	19	25
Other	47	57
Total long-term regulatory assets	421	473
Non-ARO cost of removal (Note 5D)	(732)	(671)
Net nuclear decommissioning trust unrealized gains (Note 5D)	(135)	(125)
Clean Smokestacks Act compliance (Note 7B)	(317)	(248)
Other	(12)	(8)
Total long-term regulatory liabilities	(1,196)	(1,052)
Net regulatory liabilities	$ (514)	$ (439)

PEF

(in millions)	**2005**	2004
Deferred fuel cost - current (Note 7C)	**$ 341**	$ 89
Deferred fuel cost – long-term (Note 7C)	**–**	79
Storm deferral (Note 7C)	**208**	291
Income taxes recoverable through future rates (Note 14)	**59**	49
Loss on reacquired debt (Note 1D)	**29**	31
Postretirement benefits	**7**	7
Other	**48**	67
Total long-term regulatory assets	**351**	524
Deferred energy conservation cost - current	**(10)**	(8)
Non-ARO cost of removal (Note 5D)	**(839)**	(1,210)
Deferred impact of ARO (Note 1D)	**(80)**	(26)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(116)**	(99)
Derivative mark-to-market adjustment (Note 18A)	**(122)**	(2)
Other	**(32)**	(25)
Total long-term regulatory liabilities	**(1,189)**	(1,362)
Net regulatory liabilities	**$ (507)**	$ (757)

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

B. PEC Retail Rate Matters

FUEL COST RECOVERY

On April 27, 2005, PEC filed for an increase in the fuel rate charged to its South Carolina retail customers with the SCPSC. PEC requested the $99 million increase for under-recovered fuel costs for the previous 15 months and to meet future expected fuel costs. On June 23, 2005, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceeding. The settlement agreement levelizes the collection of under-recovered fuel costs over a three-year period and allows PEC to charge and recover carrying costs on the monthly unpaid balance, beginning July 1, 2006, at an interest rate of 6% compounded annually. An annual increase in PEC's rates of $55 million, or 12 percent, was effective July 1, 2005. Residential electric bills increased by $7.29 per 1,000 kWhs for fuel cost recovery. The South Carolina deferred fuel balance at December 31, 2005, was $38 million, of which $21 million will be collected after 2006 in accordance with the settlement agreement and therefore has been classified as a long-term regulatory asset.

On June 3, 2005, PEC filed for an increase in the fuel rate charged to its North Carolina retail customers with the NCUC. PEC requested that the NCUC approve an annual increase of $276 million, or 11 percent. PEC requested the increase for under-recovered fuel costs for the previous 12 months and to meet future expected fuel costs. On September 26, 2005, the NCUC approved a settlement agreement proposed by PEC and other parties to the proceeding. In the settlement, PEC will collect all of its fuel cost under-collections that occurred during the test year ended March 31, 2005, over a one-year period beginning October 1, 2005. PEC agreed to reduce its proposed billing increment, designed to collect future fuel costs, in order to address customer concerns regarding the magnitude of the proposed increase. The NCUC approved an annual increase of $133 million, an average increase of 5 percent. In recognition of the likely under-collection that will result during the year ending September 30, 2006, PEC is allowed to calculate and collect interest at 6% on the difference between its collection factor in the original request to the NCUC and the factor included in the settlement agreement until such amounts have been collected. Effective October 1, 2005, residential electric bills increased by $3.71 per 1,000 kilowatt-hours (kWhs) for fuel cost recovery. At December 31, 2005, PEC's North Carolina retail fuel costs were under-recovered by $254 million. This amount was comprised of $244 million eligible for recovery in 2006 and $10 million deferred from a 2001 NCUC order that cannot be collected until 2007 and therefore has been classified as a long-term regulatory asset.

In 2004 and 2003, PEC obtained SCPSC and NCUC approval of fuel factors in annual fuel-adjustment proceedings. The NCUC approved an annual increase of $62 million and $20 million, respectively, by orders issued in September 2004 and 2003. The SCPSC approved PEC's petition each year and the changes were insignificant.

STORM COST RECOVERY

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

In October 2003, PEC filed with the NCUC seeking permission to defer expenses incurred from Hurricane Isabel and the February 2003 winter storms. In December 2003, the NCUC approved PEC's request to defer the costs associated with Hurricane Isabel and the February 2003 winter storms and amortize them over a period of five years. PEC charged approximately $24 million in 2003 from Hurricane Isabel and from winter storms to the deferred account. PEC recognized $5 million, $5 million and $3 million of North Carolina storm amortization during 2005, 2004 and 2003, respectively.

OTHER MATTERS

The NCUC and SCPSC have approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The aggregate minimum and maximum amounts of cost recovery are $530 million and $750 million, respectively. Accelerated cost recovery of these assets resulted in no additional expense in 2005, 2004 or 2003. Through December 31, 2005, PEC recorded total accelerated depreciation of $403 million.

The North Carolina Clean Smokestacks Act (Clean Smokestacks Act) enacted in June 2002 requires state utilities to reduce emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from coal-fired plants. The law provides that the utilities shall amortize and recover the original estimated costs (subject to adjustment by the NCUC) associated with meeting the new emission standards over a seven-year period beginning January 1, 2003. The legislation provides for significant flexibility in the amount of annual amortization recorded, which allows the utilities to vary the amount amortized within certain limits. This flexibility provides a utility with the opportunity to consider the impacts of other factors on its regulatory return on equity (ROE) when setting the amortization amount for each year. PEC recognized $147 million, $174 million and $74 million of Clean Smokestacks Act amortization during 2005, 2004 and 2003, respectively. This legislation freezes PEC's base rates in North Carolina through December 31, 2007, subject to certain conditions (See Note 22B).

In conjunction with our acquisition of Florida Progress Corporation (Florida Progress), PEC reached a settlement with the Public Staff of the NCUC in which it agreed to provide $20 million of credits to its nonreal-time pricing customers including $6 million in both 2005 (the last year the agreed-upon credits were provided) and 2004 and $5 million in 2003.

C. PEF Retail Rate Matters

STORM COST RECOVERY

On July 14, 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. The ruling allowed PEF to include a charge of approximately $3.27 on the average residential monthly customer bill of 1,000 kWhs beginning August 1, 2005. The ruling by the FPSC approved the majority of PEF's requests with two exceptions: the reclassification of $8 million of previously deferred costs to utility plant and the reclassification of $17 million of previously deferred costs as normal operation and maintenance (O&M) expense, which was expensed in the second quarter of 2005. In 2005, PEF recorded approximately $50 million of amortization associated with the recovery of these storm costs.

The amount included in the original petition requesting recovery of $252 million in November 2004 was an estimate, as actual total costs were not known at that time. On September 12, 2005, PEF filed a true-up to the original amount requested. PEF incurred an additional $19 million in costs in excess of the amount requested in the original petition. This increase was partially offset by a $6 million of adjustments due to allocating a higher portion of the costs to the wholesale jurisdiction and refining the FPSC adjustments. On November 9, 2005, as part of the action taken by the FPSC on PEF's pass-through clause cost recovery discussed below, the recovery of this difference was administratively approved by the FPSC, subject to audit by the FPSC staff. The net impact was included in customer bills beginning January 1, 2006.

On June 1, 2005, the governor of Florida signed into law a bill that allows utilities to petition the FPSC to use securitized bonds to recover storm-related costs. PEF is reviewing whether it will seek FPSC approval to issue securitized debt to recover any outstanding balance of its 2004 storm costs and to replenish its storm reserve fund, or to continue the current replenishment of its storm reserve fund through base rates and a surcharge mechanism. If PEF seeks recovery through securitization and assuming FPSC approval, PEF expects the process to take six to nine months to complete.

PASS-THROUGH CLAUSE COST RECOVERY

On November 9, 2005, the FPSC approved PEF's filed request seeking a total increase of $605 million over 2005 to recover rising fuel costs as well as costs related to other pass-through clauses and surcharges. Fuel costs of $560 million and certain purchased power costs of $42 million were the largest component of the total increase. The fuel cost increase includes $17 million from 2004 under-recoveries, $222 million from 2005 under-recoveries and a $321 million increase for 2006. Beginning January 1, 2006, residential electric bills increased by $11.78 per 1,000 kWhs each billing cycle through December 31, 2006. At December 31, 2005, PEF was under-recovered in fuel and capacity costs by $341 million.

To encourage energy conservation, the FPSC's ruling allows PEF to implement a two-tiered fuel rate for residential customers that charges a lower rate for the first 1,000 kWhs and a higher rate for each additional kWh.

BASE RATE SETTLEMENT

On April 29, 2005, PEF submitted minimum filing requirements, based on a 2006 projected test year, to initiate a base rate proceeding regarding its future base rates. In its filing, PEF requested a $206 million annual increase in base rates effective January 1, 2006. On September 7, 2005, the FPSC approved an agreement (Base Rate Settlement) that maintains PEF's base rates at their current level through late 2007, except as modified elsewhere in the Base Rate Settlement. The new base rates took effect 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 through the last billing cycle of June 2010.

Under the Base Rate Settlement, PEF will continue to collect a return on and depreciation of Hines Unit 2 through the fuel clause, as was permitted under the terms of the existing Stipulation and Settlement Agreement (the Agreement), through late 2007 when it will be transferred into base rates. This transfer will correspond with the in-service dates of the Hines Unit 4, which will also be recovered through a base rate increase. PEF began recovering the cost of its Hines Unit 3 through existing base rates when it was placed into service in November 2005, similar to other utility property additions.

The Base Rate Settlement authorizes PEF to recover certain costs through clauses, such as the continued 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.

The Base Rate Settlement also provides for revenue sharing between PEF and its customers. In 2006, PEF will refund two-thirds of retail, base revenues between the $1.499 billion threshold and the $1.549 billion cap and 100 percent of revenues above the $1.549 billion cap. Both the threshold and cap will be adjusted annually for rolling average 10-year retail kWh sales growth.

The Base Rate Settlement authorizes PEF to include an adjustment to increase common equity for the impact of Standard & Poor's (S&P's) imputed off-balance sheet debt for future capacity payments to qualifying facilities and other entities under long-term purchase power agreements. This adjusted capital structure will be used for surveillance reporting with the FPSC and pass-through clause return calculations. PEF will use an authorized 11.75 percent ROE for cost recovery clauses and AFUDC. In addition, PEF's adjusted equity ratio will be capped at 57.83 percent. If PEF's regulatory ROE falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

The FPSC requires that PEF perform a depreciation study no less frequently than every four years. PEF filed a depreciation study for the FPSC's approval on April 29, 2005, as part of its base rate filing, which would increase depreciation expense by $14 million beginning in 2006. PEF reduced its estimated removal costs to take into account the estimates used in the depreciation study. This resulted in a downward revision in PEF's estimated removal costs, a component of regulatory liabilities, and an equal increase in accumulated depreciation of $401 million. On September 7, 2005, the FPSC approved a modification to the study that resulted in a decrease to the filed report of $40 million. Consequently, the impact of the rate changes in the depreciation study will decrease annual depreciation expense by $26 million beginning in 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF filed an updated fossil dismantlement study with the FPSC on April 29, 2005, as part of its base rate filing. The new study called for an increase in the annual accrual of $10 million beginning in 2006. PEF's reserve for fossil plant dismantlement, including amounts in the ARO liability for asbestos abatement, was $145 million at December 31, 2005. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended through December 2005 under the terms of PEF's existing Agreement. The Base Rate Settlement continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF filed a new site-specific estimate of decommissioning costs for CR3 with the FPSC on April 29, 2005, as part of PEF's base rate filing. PEF's estimate is based on prompt dismantlement decommissioning. The estimate, in 2005 dollars, is $614 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. An application to extend this license 20 years is expected to be submitted in the first quarter of 2009. As part of this new estimate and assumed license extension, PEF reduced its ARO liability by $88 million. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of the Agreement and the new Base Rate Settlement continues that suspension.

FRANCHISE MATTERS

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

OTHER MATTERS

On June 29, 2004, the FPSC approved a Stipulation and Settlement Agreement, executed on April 29, 2004, by PEF, the Office of Public Counsel and the Florida Industrial Power Users Group. The stipulation and settlement resolved the issue pending before the FPSC regarding the costs PEF will be allowed to recover through its Fuel and Purchased Power Cost Recovery clause in 2004 and beyond for waterborne coal deliveries by PEF's affiliated coal supplier, Progress Fuels. The settlement sets fixed per ton prices based on point of origin for all waterborne coal deliveries in 2004, and establishes a market-based pricing methodology for determining recoverable waterborne coal transportation costs through a competitive solicitation process or market price proxies in 2005 and thereafter. The settlement reduces the amount that PEF will charge to the Fuel and Purchased Power Cost Recovery clause for waterborne transportation by approximately $11 million beginning in 2004.

On November 3, 2004, the FPSC approved PEF's petition for Determination of Need for the construction of a fourth unit at PEF's Hines Energy Complex. Hines Unit 4 is needed to maintain electric system reliability and integrity and to continue to provide adequate electricity to its ratepayers at a reasonable cost. Hines Unit 4 will be a combined cycle unit with a generating capacity of 461 MW (summer rating). The estimated total in-service cost of Hines Unit 4 is $286 million, and the unit is planned for commercial operation in December 2007. If the actual cost is less than the estimate, customers will receive the benefit of such cost under-runs. Any costs that exceed this estimate will not be recoverable absent extraordinary circumstances as found by the FPSC in subsequent proceedings.

D. Regional Transmission Organizations

In 2000, the FERC issued Order No. 2000 regarding regional transmission organizations (RTOs). This Order set minimum characteristics and functions that 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. On August 11, 2005, the GridSouth participants notified the FERC that they had terminated the GridSouth project. By order issued October 20, 2005, the FERC terminated the GridSouth proceeding. PEC has $33 million invested in GridSouth related to startup costs at December 31, 2005. PEC expects to recover these startup costs.

The FPSC ruled in December 2001 that the formation of GridFlorida by the three major investor-owned utilities in Florida, including PEF, was prudent but ordered changes in the structure and market design of the proposed organization. In September 2002, the FPSC set a hearing for market design issues; this order was appealed to the Florida Supreme Court by the consumer advocate of the state of Florida. In June 2003, the Florida Supreme Court dismissed the appeal without prejudice. In September 2003, the FERC held a Joint Technical Conference with the FPSC to consider issues related to formation of an RTO for peninsular Florida. In December 2003, the FPSC ordered further state proceedings and established a collaborative workshop process to be conducted during 2004. In June 2004, the workshop process was abated pending completion of a cost-benefit study. On December 12, 2005, the final report of the cost-benefit study was issued. The study concluded that the GridFlorida RTO was not cost effective. The study further segregated the costs and benefits between FPSC jurisdictional and nonjurisdictional customers, concluding that the jurisdictional customers would incur even more costs and benefits would be shifted to nonjurisdictional customers. In light of the findings and conclusions of the cost-benefit study, on January 27, 2006, the GridFlorida applicants filed a motion to withdraw the compliance filing and filed a petition to close the docketed proceeding. The Florida Municipal Power Agency and Seminole Electric Power Cooperative have submitted a filing in opposition to this motion. The FPSC has released a schedule that indicates that they will issue an order on this motion by April 24, 2006. The GridFlorida applicants are currently in discussions to determine whether there are cost-effective alternatives to the GridFlorida proposal that could be implemented in peninsular Florida. PEF has fully recovered its startup costs in GridFlorida from retail ratepayers.

E. FERC Market Power Mitigation

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

F. Energy Delivery Capitalization Practice

We reviewed our capitalization policies for the Utilities' distribution operations (Energy Delivery) in 2004. That review indicated that in the areas of outage and emergency work not associated with major storms and allocation of indirect costs, both PEC and PEF should revise the way that they estimate the amount of capital costs associated with such work. Effective January 1, 2005, we implemented changes that included more detailed classification of outage and emergency work resulting in more precise estimation and implemented a process to retest accounting estimates on an annual basis. As a result of the changes in accounting estimates for the outage and emergency work and indirect costs, a lesser proportion of PEC's and PEF's costs will be capitalized on a prospective basis. The combined impact for the Utilities in 2005 was to expense approximately $63 million of costs that would have been capitalized under the previous policies. Of this total, $26 million related to PEC and $37 million related to PEF. Pursuant to SFAS No. 71, the Utilities informed the state regulators having jurisdiction over them of this change and that the new estimation process was implemented effective January 1, 2005. We also requested and received a method change from the Internal Revenue Service (IRS) during 2005.

8. GOODWILL AND OTHER INTANGIBLE ASSETS

We perform annual goodwill impairment tests in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Goodwill impairment was tested for both the PEC and PEF segments in the second quarters of 2004 and 2005; each test indicated no impairment.

For our Progress Ventures segment, the goodwill impairment tests are performed at the reporting unit level of our Effingham, Monroe, Walton and Washington nonregulated generation plants (Georgia Region), which is one level below the Progress Ventures segment. We performed the annual goodwill impairment test for our Georgia Region reporting unit in the first quarters of 2005 and 2004, each of which indicated no impairment. In response to changing gas and electricity prices that have a significant impact on the future cash flows of our Georgia Region operations, we also performed an interim goodwill impairment test for the Progress Ventures goodwill in the third and fourth quarters of 2005, each of which indicated no impairment. However, as part of our evaluation of certain business opportunities in the first quarter of 2006, we performed an interim impairment test for the $64 million of goodwill, which indicated the fair value of the Georgia Region was less than its carrying value. As required by SFAS No. 142, we are currently performing the second step of the impairment test, which compares the implied fair value of the goodwill with the recorded goodwill. While the results of the second step of the impairment test are currently unknown, the effects could range from no change to the recorded goodwill value to a potential write-off of $64 million.

Under SFAS No. 142, all goodwill is assigned to our reporting units that are expected to benefit from the synergies of the business combination. The changes in the carrying amount of goodwill, by reportable segment for the years ended December 31 were as follows:

(in millions)	PEC	PEF	Progress Ventures	Corporate and Other	Total
Balance at January 1, 2003	$ 1,922	$ 1,733	$ 64	$ –	$ 3,719
Acquisitions	–	–	–	7	7
Balance at December 31, 2003	1,922	1,733	64	7	3,726
Purchase accounting adjustment	–	–	–	(7)	(7)
Balance at December 31, 2004	1,922	1,733	64	–	3,719
Balance at December 31, 2005	**$ 1,922**	**$ 1,733**	**$ 64**	**$ –**	**$ 3,719**

In December 2003, $7 million in goodwill was recorded based on a preliminary purchase price allocation as part of the PTC partial acquisition of EPIK and was reported in the Corporate and Other segment. As discussed in Note 4B, we revised the preliminary EPIK purchase price allocation as of September 2004, and the $7 million of goodwill was reallocated to certain tangible assets acquired based on the results of valuations and appraisals.

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

	2005		2004	
(in millions)	**Gross Carrying Amount**	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
Synthetic fuel intangibles	**$ 134**	**$ (98)**	$ 134	$ (80)
Power agreements acquired	**188**	**(19)**	188	(6)
Other	**112**	**(15)**	111	(11)
Total	**$ 434**	**$ (132)**	$ 433	$ (97)

In June 2004, we sold, in two transactions, a combined 49.8 percent partnership interest in Colona, one of our synthetic fuel operations. Approximately $6 million in synthetic fuel intangibles and $3 million in related accumulated amortization were included in the sale of the partnership interest.

All of our intangibles, except minimum pension liability adjustments, are subject to amortization. Synthetic fuel intangibles represent intangibles for synthetic fuel technology. These intangibles are being amortized on a straight-line basis until the expiration of tax credits under Section 29/45K in December 2007 (See Note 23D). The intangibles related to power agreements acquired are being amortized based on the economic benefits of the contracts (See Notes 4D). Other intangibles are primarily acquired customer contracts, permits that are amortized over their respective lives and minimum pension liability adjustments.

PEC had intangible assets related to minimum pension liability adjustments of $17 million and $18 million at December 31, 2005 and 2004, respectively. PEF had intangible assets related to minimum pension liability adjustments of $2 million at December 31, 2005.

Amortization expense recorded on intangible assets for the years ended December 31, 2005, 2004 and 2003 was $35 million, $42 million and $36 million, respectively. The estimated annual amortization expense for intangible assets for 2006 through 2010 is approximately $36 million, $37 million, $18 million, $18 million and $19 million, respectively.

9. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. In 2005 and 2003, we recorded pre-tax long-lived asset and investment impairments and other charges of $1 million and $38 million, respectively. PEC recorded pre-tax long-lived asset and investment impairments and other charges of $1 million and $21 million, respectively, in 2005 and 2003. No impairments were recorded in 2004.

A. Long-Lived Assets

Due to the reduction in coal production, we evaluated Kentucky May coal mine's long-lived assets in 2003. Fair value was determined based on discounted cash flows. As a result of this review, we recorded asset impairments of $17 million on a pre-tax basis during the fourth quarter of 2003. As discussed in Note 3A, all amounts directly related to the coal mines are included in discontinued operations on the consolidated statements of income. Due to rising current and future oil prices, in the third and fourth quarters of 2005 we tested our synthetic fuel plant assets for impairment. These tests indicated that the assets were recoverable and no impairment charge was recorded. See Note 23D for additional information.

B. Investments

We evaluate declines in value of investments under the criteria of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), and Emerging Issues Task Force (EITF) Issue No. 03-1, "The Meaning of Other-Than-Temporary Impairments and Its Application to Certain Investments" (EITF 03-1). Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in impairments of investments. See Note 13 for additional information.

We continually review PEC's affordable housing investment (AHI) portfolio for impairment. As a result of various factors including continued operating losses of the AHI portfolio and management issues arising at certain properties within the AHI portfolio, we recorded impairment charges of $1 million and $18 million on a pre-tax basis in 2005 and 2003, respectively. PEC also recorded an impairment of $3 million for a cost investment in 2003. No impairments were recorded in 2004.

10. EQUITY

A. Common Stock

Progress Energy

At December 31, 2005 and 2004, we had 500 million shares of common stock authorized under our charter, of which 252 million shares and 247 million shares, respectively, were outstanding. At December 31, 2005 and 2004, we had approximately 58 million shares and 63 million shares, respectively, of common stock authorized by the board of directors that remained unissued and reserved, primarily to satisfy the requirements of our stock plans. In 2002, the board of directors authorized meeting the requirements of the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan with original issue shares. During 2005, 2004 and 2003, respectively, we issued approximately 4.6 million, 1.4 million and 7.5 million shares, respectively, under these plans for net proceeds of approximately $199 million, $62 million and $305 million, respectively. We continue to meet the requirements of the restricted stock plan with issued and outstanding shares.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2005, there were no significant restrictions on the use of retained earnings (See Note 12).

PEC

At December 31, 2005 and 2004, 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, 2005, there were no significant restrictions on the use of retained earnings. See Note 12 for additional dividend restrictions related to PEC.

PEF

At December 31, 2005 and 2004, 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, 2005, there were no significant restrictions on the use of retained earnings. See Note 12 for additional dividend restrictions related to PEF.

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. Participating subsidiaries as of January 1, 2003, were PEC, PEF, PTC, PVI, Progress Fuels (corporate employees) and Progress Energy Service Company, LLC (PESC). Effective December 19, 2003, (the PT LLC/EPIK merger date), PTC no longer participates in the 401(k). 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. To the extent used to repay such loans, the dividends are deductible for income tax purposes. Also, beginning in 2002, the dividends paid on ESOP shares that are either paid directly to participants or used to purchase additional shares which are subsequently allocated to participants, are fully deductible for income tax purposes.

There were 2.9 million and 3.5 million ESOP suspense shares at December 31, 2005 and 2004, respectively, with a fair value of $126 million and $156 million, respectively. ESOP shares allocated to plan participants totaled 11.4 million and 12.6 million at December 31, 2005 and 2004, 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 $18 million, $21 million and $20 million for the years ended December 31, 2005, 2004 and 2003, respectively. Total matching and incentive costs totaled approximately $30 million, $32 million and $35 million for the years ended December 31, 2005, 2004 and 2003, respectively. We have a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

PEC

PEC's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $11 million, $12 million and $11 million for the years ended December 31, 2005, 2004 and 2003, respectively. Matching and incentive costs totaled approximately $17 million, $18 million and $16 million for the years ended December 31, 2005, 2004 and 2003, respectively.

PEF

PEF's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $4 million, $5 million and $4 million for the years ended December 31, 2005, 2004 and 2003, respectively. Matching and incentive costs totaled approximately $6 million, $7 million and $10 million for the years ended December 31, 2005, 2004 and 2003, respectively.

NEW ACCOUNTING FOR STOCK-BASED COMPENSATION

In December 2004, the FASB issued SFAS No. 123R, which revises SFAS No. 123, "Accounting for Stock-Based Compensation," and supersedes Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB Opinion No. 25). The key requirement of SFAS No. 123R is that the cost of stock-based awards to employees will be measured based on an award's fair value at the grant date, with such cost to be amortized over the appropriate service period, net of estimated forfeitures. Previously, entities could elect to continue accounting for such awards at their grant date intrinsic value under APB Opinion No. 25, and we made that election. The intrinsic value method resulted in our recording no compensation expense for stock options granted to employees. Also, as previously allowed, we recognized the expense effects of forfeitures as they occurred. SFAS No. 123R also changes prospectively the presentation of certain stock-based compensation excess income tax benefits in the statement of cash flows, with such excess tax benefits shown as financing cash inflows rather than operating cash inflows.

We adopted SFAS No. 123R as of July 1, 2005, using the required modified prospective method. Under that method, we will record compensation expense under SFAS No. 123R for all awards granted after July 1, 2005, and will record compensation expense (as previous awards continue to vest) for the unvested portion of previously granted awards that were outstanding at July 1, 2005. For awards with graded-vesting features, we will recognize expense using the grading-vesting method alternative in SFAS No. 123R. As a result of the adoption of SFAS No. 123R, on a prospective basis, we will not show unearned restricted shares as a negative component of common stock equity; rather, such amounts will be included in the determination of common stock presented in the Consolidated Balance Sheets. In addition, on a prospective basis, for new awards that effectively vest upon an employee's retirement eligibility, we will recognize expense over a vesting period based on the effective vesting date. Previously, we recognized expense over a vesting period based on the stated vesting date.

Progress Energy

Adoption of SFAS No. 123R resulted in our recognizing approximately $3 million of pre-tax expense for stock options during the year ended December 31, 2005, which would not have been recognized under the prior accounting treatment. We curtailed our stock option program in 2004 and replaced that compensation program with other programs. Therefore, the amount of stock option expense recorded in 2005 is below the amount that would have been recorded if the stock option program had continued. Additionally, we recognized a cumulative pre-tax benefit from the accounting change of approximately $1 million, which reflects the cumulative impact of estimating forfeitures in the determination of period expense for other stock-based compensation plans, rather than recording the effect of forfeitures as they occur. As a result of the adoption of SFAS No. 123R, on a prospective basis we will not show unearned restricted shares as a negative component of common stock equity; rather, such amounts will be included in the determination of common stock presented in the Consolidated Balance Sheets. The adoption of SFAS No. 123R did not have a material impact on our income, earnings per share or our presentation of cash flows for the year ended December 31, 2005.

PEC

PEC participates in the Progress Energy stock option and other stock-based compensation plans and its adoption of SFAS No. 123R resulted in the recognition of approximately $1 million of pre-tax expense for stock options for the year ended December 31, 2005, which would not have been recognized under the prior accounting treatment. Additionally, PEC recognized an immaterial amount of cumulative pre-tax benefit from the accounting change which reflects the cumulative impact of estimating forfeitures in the determination of period expense for other stock-based compensation plans, rather than recording the effect of forfeitures as they occur. The adoption of SFAS No. 123R did not have a material impact on PEC's income or PEC's presentation of cash flows for the year ended December 31, 2005.

PEF

PEF participates in the Progress Energy stock option and other stock-based compensation plans and its adoption of SFAS No. 123R resulted in the recognition of approximately $1 million of pre-tax expense for stock options for the year ended December 31, 2005, which would not have been recognized under the prior accounting treatment. Additionally, PEF recognized an immaterial amount of cumulative pre-tax benefit from the accounting change which reflects the cumulative impact of estimating forfeitures in the determination of period expense for other stock-based compensation plans, rather than recording the effect of forfeitures as they occur. The adoption of SFAS No. 123R did not have a material impact on PEF's income or PEF's presentation of cash flows for the year ended December 31, 2005.

STOCK OPTIONS

Pursuant to our 1997 Equity Incentive Plan and 2002 Equity Incentive Plan, amended and restated as of July 10, 2002, we may grant options to purchase shares of Progress Energy common stock to directors, officers and eligible employees for up to 5 million and 15 million shares, respectively. Generally, options granted to employees vest one-third per year with 100 percent vesting at the end of year three, while options granted to directors vest 100 percent at the end of one year. The options expire 10 years from the date of grant. All option grants have an exercise price equal to the fair market value of our common stock on the grant date. As noted above, we have ceased granting stock options. An immaterial number of stock options were granted in 2004 and no stock options have been granted in 2005. 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, 2005, and changes during the year then ended, is presented below:

(option quantities in millions)	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	7.4	$43.57
Granted	–	–
Forfeited	(0.1)	$44.12
Canceled	(0.1)	$43.75
Exercised	(0.2)	$42.70
Options outstanding, December 31	7.0	$43.58
Options exercisable, December 31	6.0	$43.40

The options outstanding at December 31, 2005, had a weighted-average remaining contractual life of 6.6 years and an aggregate intrinsic value of $5 million. The options exercisable at December 31, 2005, had a weighted-average remaining contractual life of 6.4

years and an aggregate intrinsic value of $5 million.

The total intrinsic value of options exercised during the year ended December 31, 2004, was $1 million. Total intrinsic value of options exercised during the years ended December 31, 2005 and 2003, was less than $1 million in each year.

Compensation cost, for pro forma purposes prior to the adoption of SFAS No. 123R and for expense purposes subsequent to the adoption, is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted-average assumptions:

	2004	2003
Risk-free interest rate	4.22%	4.25%
Dividend yield	5.19%	4.75%
Volatility factor	20.30%	22.28%
Weighted-average expected life of the options (in years)	10	10

Dividend yield and the volatility factor were calculated using three years of historical trend information. The expected term was based on the contractual life of the options.

Stock option expense totaling $3 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year.

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

(in millions except per share data)	**2005**	2004	2003
Net income, as reported	**$ 697**	$ 759	$ 782
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	**2**	10	11
Pro forma net income	**$ 695**	$ 749	$ 771
Earnings per share			
Basic – as reported	**$ 2.82**	$ 3.13	$ 3.30
Basic – pro forma	**2.81**	3.09	3.25
Diluted – as reported	**2.82**	3.12	3.28
Diluted – pro forma	**2.81**	3.08	3.24

At December 31, 2005, there was $2 million of total unrecognized compensation cost related to nonvested stock options that will be recognized over one year.

Cash received from the exercise of stock options totaled $8 million, $18 million and $4 million, respectively, during the years ended December 31, 2005, 2004 and 2003. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2005, 2004 and 2003 was not significant.

PEC

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. At December 31, 2005, there was $1 million of total unrecognized compensation cost related to nonvested stock options which will be recognized over one year.

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

(in millions)	**2005**	2004	2003
Net income, as reported	**$493**	$461	$482
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	**2**	7	6
Pro forma net income	**$491**	$454	$476

PEF

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. At December 31, 2005, there was less than $1 million of total unrecognized compensation cost related to nonvested stock options which will be recognized over one year.

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

(in millions)	**2005**	2004	2003
Net income, as reported	**$260**	$335	$297
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	**1**	2	2
Pro forma net income	**$259**	$333	$295

OTHER STOCK-BASED COMPENSATION PLANS

We have additional compensation plans for our officers and key employees that are stock-based in whole or in part. The two primary active stock-based compensation programs are the Performance Share Sub-Plan (PSSP) and the Restricted Stock Awards (RSA) program, both of which were established pursuant to our 1997 Equity Incentive Plan and were continued under our 2002 Equity Incentive Plan, as amended and restated as of July 10, 2002.

We granted cash-settled PSSP awards prior to 2005. Beginning in 2005, we are granting stock-settled PSSP awards. Under the terms of the cash-settled PSSP, our officers and key employees are granted a target number of performance shares on an annual basis that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of Progress Energy common stock, and dividend equivalents are accrued on, and reinvested in, the performance shares. The PSSP has two equally weighted performance measures, both of which are based on our results as compared to a peer group of utilities. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. Compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. The stock-settled PSSP is similar to the cash-settled PSSP, except that we distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with certain subsequent adjustments related to our results as compared to the peer group of utilities. PSSP cash-settled liabilities totaling $5 million, $7 million and $6 million were paid in the years ended December 31, 2005, 2004 and 2003, respectively. In 2005, we granted 540,588 stock-settled performance shares having a weighted-average grant date fair value of $44.24, with no forfeitures as of December 31, 2005.

The RSA program allows us to grant shares of restricted common stock to our officers and key employees. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. Restricted shares are not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. A summary of the status of the nonvested restricted stock shares at December 31, 2005, and changes during the year then ended, is presented below:

	Number of Restrict Shares	Weighted-Average Grant Date Fair Value
Beginning balance	645,176	$42.32
Granted	192,800	42.56
Vested	(149,934)	38.75
Forfeited	(99,734)	42.53
Ending balance	588,308	$43.27

The weighted-average grant date fair value of restricted stock granted during the years ended December 31, 2004 and 2003, was $46.95 and $39.53, respectively.

The total fair value of restricted stock vested during the years ended December 31, 2005, 2004 and 2003 was $7 million, $16 million and $6 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million, $7 million and $7 million during the years ended December 31, 2005, 2004 and 2003, respectively.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $10 million for the year ended December 31, 2005, with a recognized tax benefit of $4 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $10 million for the year ended December 31, 2004, with a recognized tax benefit of $4 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $27 million for the year ended December 31, 2003, with a recognized tax benefit of $10 million. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2005, 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 2.2 years.

PEC

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $7 million for the year ended December 31, 2005, with a recognized tax benefit of $3 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $7 million for the year ended December 31, 2004, with a recognized tax benefit of $3 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $15 million for the year ended December 31, 2003, with a recognized tax benefit of $6 million. No compensation cost related to other stock-based compensation plans was capitalized.

PEF

Our Statements of Income included total recognized expense for other stock-based compensation plans of $3 million for the year ended

December 31, 2005, with a recognized tax benefit of $1 million. The total expense recognized on our Statements of Income for other stock-based compensation plans was $2 million for the year ended December 31, 2004, with a recognized tax benefit of $1 million. The total expense recognized on our Statements of Income for other stock-based compensation plans was $7 million for the year ended December 31, 2003, with a recognized tax benefit of $3 million. No compensation cost related to other stock-based compensation plans was capitalized.

C. Earnings Per Common Share

Basic earnings per common share is based on the weighted-average number of common shares outstanding. Diluted earnings per share includes the effect of the nonvested portion of restricted stock awards and the effect of stock options outstanding.

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

(in millions)	**2005**	2004	2003
Weighted-average common shares – basic	**246.6**	242.2	237.2
Restricted stock awards	**.3**	.8	1.0
Stock options	**.1**	.1	–
Weighted-average shares – fully diluted	**247.0**	243.1	238.2

There are no adjustments to net income or to income from continuing operations between the calculations of basic and fully diluted earnings per common share. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. The weighted-average shares totaled 3.0 million, 3.6 million and 4.1 million for the years ended December 31, 2005, 2004 and 2003, respectively. There were 2.9 million, 3.0 million and 5.3 million stock options outstanding at December 31, 2005, 2004 and 2003, 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	
(in millions)	**2005**	2004	**2005**	2004
Gain (loss) on cash flow hedges	**$ 55**	$ (28)	$ (3)	$ (7)
Minimum pension liability adjustments	**(160)**	(142)	(119)	(107)
Foreign currency translation and other	**1**	6	2	–
Total accumulated other comprehensive loss	**$ (104)**	$ (164)	$ (120)	$ (114)

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

All of our preferred stock was issued by our subsidiaries and was not subject to mandatory redemption. At December 31, 2005 and 2004, 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				
	4,000,000			
Cumulative, $100 par value Preferred Stock				
4.00% $100 par value Preferred		39,980	$104.25	4
4.40% $100 par value Preferred		75,000	102.00	8
4.58% $100 par value Preferred		99,990	101.00	10
4.60% $100 par value Preferred		39,997	103.25	4
4.75% $100 par value Preferred		80,000	102.00	8
Cumulative, no par value Preferred Stock	5,000,000	–	–	–
$100 par value Preference Stock	1,000,000	–	–	–
Total PEF				34
Total preferred stock of subsidiaries				$ 93

12. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2005):

(in millions)		2005	2004
Progress Energy, Inc.			
Senior unsecured notes, maturing 2006-2031	6.78%	**$ 4,300**	$ 4,300
Draws on revolving credit agreement, expiring 2009		**–**	160
Unamortized fair value hedge gain, net		**(3)**	12
Unamortized premium and discount, net		**(19)**	(23)
Current portion of long-term debt		**(404)**	–
Long-term debt, net		**3,874**	4,449
PEC			
First mortgage bonds, maturing 2006-2033	5.76%	**2,200**	1,600
Pollution control obligations, maturing 2017-2024	3.21%	**669**	669
Unsecured notes, maturing 2012	6.50%	**500**	500
Medium-term notes, maturing 2008	6.65%	**300**	300
Miscellaneous notes		**22**	–
Unamortized premium and discount, net		**(24)**	(19)
Current portion of long-term debt		**–**	(300)
Long-term debt, net		**3,667**	2,750
PEF			
First mortgage bonds, maturing 2008-2033	5.39%	**1,630**	1,330
Pollution control obligations, maturing 2018-2027	3.07%	**241**	241
Senior unsecured notes, maturing 2008	4.88%	**450**	–
Medium-term notes, maturing 2006-2028	6.77%	**289**	337
Draws on revolving credit agreement, expiring 2006		**–**	55
Unamortized premium and discount, net		**(8)**	(3)
Current portion of long-term debt		**(48)**	(48)
Long-term debt, net		**2,554**	1,912
Florida Progress Funding Corporation (See Note 24)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(39)**	(39)
Long-term debt, net		**270**	270
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2006-2008	6.84%	**140**	140
Miscellaneous notes		**2**	1
Current portion of long-term debt		**(61)**	(1)
Long-term debt, net		**81**	140
Progress Energy consolidated long-term debt, net		**$ 10,446**	$ 9,521

At December 31, 2005, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2005, we had no outstanding borrowings under our credit facilities. For 2004, outstanding borrowings under Progress Energy, Inc.'s 364-day credit facility are included in short-term obligations. Outstanding borrowings under all other credit facilities are included in long-term debt in 2004. At December 31, 2004, we had $260 million outstanding under our credit facilities classified as short-term obligations at a weighted-average interest rate of 3.18%. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following table summarizes our revolving credit agreements (RCAs) and available capacity at December 31, 2005:

(in millions)	Description	Total	Outstanding	Reserved(a)	Available
Progress Energy, Inc.	Five-year (expiring 8/5/09)	$ 1,130	$ –	$ (150)	$ 980
PEC	Five-year (expiring 6/28/10)	450	–	(73)	377
PEF	Five-year (expiring 3/28/10)	450	–	(102)	348
Total credit facilities		$ 2,030	$ –	$ (325)	$ 1,705

(a) To the extent amounts are reserved for commercial paper outstanding, they are not available for additional borrowings. In addition, at December 31, 2005 and 2004, Progress Energy, Inc. had a total amount of $150 million reserved for backing of letters of credit. At December 31, 2005, the actual amount of letters of credit issued was $33 million.

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

The following table summarizes our outstanding commercial paper and other short-term debt classified as short-term obligations and related weighted-average interest rates at December 31, 2005 and 2004:

(in millions)	**2005**		2004	
Progress Energy, Inc.	–	$ –	2.75%	$ 170
PEC	**4.65%**	**73**	2.77%	131
PEF	**4.75%**	**102**	2.80%	123
Progress Energy, consolidated	**4.71%**	**$ 175**	2.77%	$ 424

The following table presents the aggregate maturities of long-term debt at December 31, 2005:

(in millions)	Progress Energy Consolidated	PEC	PEF
2006	$ 513	$ –	$ 48
2007	674	200	89
2008	1,277	300	532
2009	401	400	–
2010	406	6	300
Thereafter	7,781	2,785	1,641
Total	$ 11,052	$ 3,691	$ 2,610

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

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

B. Covenants and Default Provisions

FINANCIAL COVENANTS

Progress Energy, Inc.'s, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. These include maximum debt to total capital ratios (leverage), a minimum interest coverage ratio, material adverse change clauses and cross-default provisions.

All of the credit facilities include a defined maximum total debt to total capital ratio. At December 31, 2005, the maximum and calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio (a)
Progress Energy, Inc.	68%	60.7%
PEC	65%	55.2%
PEF	65%	50.9%

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

Progress Energy, Inc.'s five-year credit facility has a financial covenant for interest coverage. The covenant requires Progress Energy, Inc.'s earnings before interest, taxes, and depreciation and amortization to interest expense ratio to be at least 2.5 to 1. For the year ended December 31, 2005, the ratio was 3.9 to 1.

MATERIAL ADVERSE CHANGE CLAUSE

Pursuant to the terms of Progress Energy, Inc.'s five-year credit facility, even in the event of a material adverse change (MAC) in our financial condition, we may continue to borrow funds so long as the proceeds are used to repay maturing commercial paper balances. The other credit facilities of Progress Energy, Inc., PEC, and PEF do not include a provision under which lenders could refuse to advance funds in the event of a MAC.

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of the following thresholds: $50 million for Progress Energy, Inc. and $35 million each for PEC and PEF. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of their respective cross-default threshold, the lenders could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. Progress Energy, Inc.'s cross-default provision applies only to Progress Energy, Inc. and its significant subsidiaries, as defined in the credit agreement, (i.e., PEC, Florida Progress, PEF, Progress Capital Holdings, Inc. and PVI). PEC's and PEF's cross-default provisions apply only to defaults of indebtedness by PEC and its subsidiaries and PEF, respectively, not other affiliates of PEC and PEF.

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

OTHER RESTRICTIONS

Neither Progress Energy, Inc.'s Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends. Certain documents restrict the payment of dividends by Progress Energy, Inc.'s subsidiaries as outlined below.

<u>PEC</u>

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, 2005, none of PEC's retained earnings was restricted.

In addition, PEC's Articles of Incorporation provide that cash dividends on common stock shall be limited to 75 percent of 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, 2005, PEC's common stock equity was approximately 45.6 percent of total capitalization.

<u>PEF</u>

PEF's mortgage indenture provides that 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, 2005, none of PEF's retained earnings was restricted.

In addition, PEF's Articles of Incorporation provide that 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, exceed 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. At December 31, 2005, none of PEF's cash dividends or distributions on common stock was restricted.

PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of 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, 2005, PEF's common stock equity was approximately 50.1 percent of total capitalization.

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, 2005, PEC and PEF had a total of approximately $2.869 billion and $1.871 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

See Note 19 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 discussion of risk management activities and derivative transactions at Note 18.

13. INVESTMENTS AND FAIR VALUE OF FINANCIAL INSTRUMENTS

A. Investments

At December 31, 2005 and 2004, 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)	**2005**	2004	**2005**	2004	**2005**	2004
Nuclear decommissioning trust (See Note 5D)	**$ 1,133**	$ 1,044	**$ 640**	$ 581	**$ 493**	$ 463
Investments in equity securities (a)	**7**	3	**6**	3	**1**	–
Equity method investments (b)	**27**	26	**15**	15	**–**	–
Cost investments (c)	**13**	14	**1**	1	**–**	–
Benefit investment trusts (d)	**77**	76	**1**	1	**–**	–
Company-owned life insurance (d)	**153**	145	**97**	93	**39**	34
Marketable debt securities (e)	**191**	82	**191**	82	**–**	–
Total	**$ 1,601**	$ 1,390	**$ 951**	$ 776	**$ 533**	$ 497

(a) Certain investments in equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115 (See Note 1). These investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. Investments in unconsolidated companies are included in the Consolidated Balance Sheets in miscellaneous other property and investments using the equity method of accounting (See Note 1). These investments are primarily in limited liability corporations and limited partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 21).

(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 and other benefit plan assets are included in miscellaneous other property and investments in the Consolidated Balance Sheets and approximate fair value due to the short maturity of the instruments. PEC actively invests available cash balances in various financial instruments, such as tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through arrangements with banks that provide daily and weekly liquidity and 7-, 28- and 35-day auctions that allow for the redemption of the investment at its face amount plus earned income. As PEC intends to sell these instruments within one year or less, generally within 30 days, from the balance sheet date, they are classified as short-term investments.

B. Fair Value of Financial Instruments

Progress Energy

DEBT

The carrying amount of our long-term debt, including current maturities, was $10.959 billion and $9.870 billion at December 31, 2005 and 2004, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $11.491 billion and $10.843 billion at December 31, 2005 and 2004, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115. These investments include investments held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning nuclear plants (See Note 5D). These nuclear decommissioning trust funds are primarily invested in stocks, bonds and cash equivalents that are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust funds, we hold other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the Consolidated Balance Sheets at amounts that approximate fair value. Our available-for-sale securities at December 31, 2005 and 2004 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2005 **(in millions)**	**Book Value**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Equity securities	**$ 411**	**$ 257**	**$ 5**	**$ 663**
Debt securities	**680**	**7**	**7**	**680**
Cash equivalents	**18**	**–**	**–**	**18**
Total	**$ 1,109**	**$ 264**	**$ 12**	**$ 1,361**

2004	Book Value	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Equity securities	$ 387	$ 219	$ 6	$ 600
Debt securities	538	12	2	548
Cash equivalents	17	–	–	17
Total	$ 942	$ 231	$ 8	$ 1,165

At December 31, 2005, the fair value of available-for-sale debt securities by contractual maturity was (in millions):

Due in one year or less	$ 15
Due after one through five years	138
Due after five through 10 years	151
Due after 10 years	376
Total	$ 680

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)	**2005**	2004	2003
Proceeds	**$ 2,053**	$ 3,200	$ 3,374
Realized gains	**26**	55	21
Realized losses	**19**	24	25

The following table presents the fair value and gross unrealized losses of our available-for-sale securities at December 31 aggregated by the length of time the securities have been in a continuous loss position.

2005	**12 Months or Less**		**Greater than 12 Months**		**Total**	
(in millions)	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**
Equity securities	**$ 653**	**$ 3**	**$ 10**	**$ 2**	**$ 663**	**$ 5**
Debt securities	**653**	**7**	**27**	**–**	**680**	**7**
Cash equivalents	**18**	**–**	**–**	**–**	**18**	**–**
Total	**$ 1,324**	**$ 10**	**$ 37**	**$ 2**	**$ 1,361**	**$ 12**

2004	12 Months or Less		Greater than 12 Months		Total	
(in millions)	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Equity securities	$ 587	$ 3	$ 13	$ 3	$ 600	$ 6
Debt securities	546	2	2	–	548	2
Cash equivalents	17	–	–	–	17	–
Total	$ 1,150	$ 5	$ 15	$ 3	$ 1,165	$ 8

PEC

DEBT

The carrying amount of PEC's long-term debt, including current maturities, was $3.667 billion and $3.050 billion at December 31, 2005 and 2004, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.789 billion and $3.307 billion at December 31, 2005 and 2004, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 5D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents and are classified as available-for-sale. Nuclear decommissioning trust funds are presented at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust fund, PEC holds other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the Consolidated Balance Sheets at amounts that approximate fair value. PEC's available-for-sale securities at December 31, 2005 and 2004 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2005 **(in millions)**	**Book Value**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Equity securities	**$ 222**	**$ 141**	**$ 4**	**$ 359**
Debt securities	**465**	**4**	**4**	**465**
Cash equivalents	**10**	**–**	**–**	**10**
Total	**$ 697**	**$ 145**	**$ 8**	**$ 834**

2004 (in millions)	Book Value	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Equity securities	$ 208	$ 123	$ 5	$ 326
Debt securities	319	7	1	325
Cash equivalents	12	–	–	12
Total	$ 539	$ 130	$ 6	$ 663

At December 31, 2005, the fair value of available-for-sale debt securities by contractual maturity was (in millions):

Due in one year or less	$ 4
Due after one through five years	78
Due after five through 10 years	80
Due after 10 years	303
Total	$ 465

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)	**2005**	2004	2003
Proceeds	**$ 1,678**	$ 2,584	$ 2,990
Realized gains	**13**	24	10
Realized losses	**8**	20	12

The following table presents the fair value and gross unrealized losses of PEC's available-for-sale securities at December 31 aggregated by the length of time the securities have been in a continuous loss position.

2005	**12 Months Or Less**		**Greater Than 12 Months**		**Total**	
(in millions)	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**
Equity securities	**$ 349**	**$ 2**	**$ 10**	**$ 2**	**$ 359**	**$ 4**
Debt securities	**451**	**4**	**14**	**–**	**465**	**4**
Cash equivalents	**10**	**–**	**–**	**–**	**10**	**–**
Total	**$ 810**	**$ 6**	**$ 24**	**$ 2**	**$ 834**	**$ 8**

2004	12 Months Or Less		Greater Than 12 Months		Total	
(in millions)	Fair Value	Unrealized Losses	Fair value	Unrealized Losses	Fair Value	Unrealized Losses
Equity securities	$ 315	$ 2	$ 11	$ 3	$ 326	$ 5
Debt securities	323	1	2	–	325	1
Cash equivalents	12	–	–	–	12	–
Total	$ 650	$ 3	$ 13	$ 3	$ 663	$ 6

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $2.602 billion and $1.960 billion at December 31, 2005 and 2004, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $2.635 billion and $2.080 billion at December 31, 2005 and 2004, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 5D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents and are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. PEF's available-for-sale securities at December 31, 2005 and 2004 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2005 **(in millions)**	**Book Value**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Equity securities	**$ 189**	**$ 116**	**$ 1**	**$ 304**
Debt securities	**182**	**3**	**2**	**183**
Cash equivalents	**5**	**–**	**–**	**5**
Total	**$ 376**	**$ 119**	**$ 3**	**$ 492**

2004 (in millions)	Book Value	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Equity securities	$ 179	$ 96	$ 1	$ 274
Debt securities	183	5	1	187
Cash equivalents	5	–	–	5
Total	$ 367	$ 101	$ 2	$ 466

At December 31, 2005, the fair value of available-for-sale debt securities by contractual maturity was (in millions):

Due in one year or less	$ 3
Due after one through five years	53
Due after five through 10 years	54
Due after 10 years	73
Total	$ 183

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)	**2005**	2004	2003
Proceeds	**$330**	$529	$295
Realized gains	**13**	30	10
Realized losses	**10**	3	12

The following table presents the fair value and gross unrealized losses of PEF's available-for-sale securities at December 31 aggregated by the length of time the securities have been in a continuous loss position.

2005	**12 Months Or Less**		**Greater Than 12 Months**		**Total**	
(in millions)	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**
Equity securities	**$ 304**	**$ 1**	**$ –**	**$ –**	**$ 304**	**$ 1**
Debt securities	**173**	**2**	**10**	**–**	**183**	**2**
Cash equivalents	**5**	**–**	**–**	**–**	**5**	**–**
Total	**$ 482**	**$ 3**	**$ 10**	**$ –**	**$ 492**	**$ 3**

2004	12 Months Or Less		Greater Than 12 Months		Total	
(in millions)	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Equity securities	$ 272	$ 1	$ 2	$ –	$ 274	$ 1
Debt securities	187	1	–	–	187	1
Cash equivalents	5	–	–	–	5	–
Total	$ 464	$ 2	$ 2	$ –	$ 466	$ 2

14. INCOME TAXES

We provide deferred income taxes for temporary differences. These occur when there are differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes under SFAS No. 109 is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders.

Progress Energy

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

(in millions)	**2005**	2004
Deferred income tax assets		
Asset retirement obligation liability	**$ 135**	$ 169
Compensation accruals	**101**	99
Deferred revenue	**54**	8
Derivative instruments	**-**	25
Environmental remediation liability	**27**	21
Income taxes refundable through future rates	**179**	115
Postretirement and pension benefits	**275**	188
Unbilled revenue	**30**	35
Other	**112**	128
Federal income tax credit carry forward	**957**	778
State net operating loss carry forward (net of federal expense)	**45**	26
Valuation allowance	**(39)**	(25)
Total deferred income tax assets	**1,876**	1,567
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,420)**	(1,513)
Deferred fuel recovery	**(89)**	(68)
Deferred storm costs	**(94)**	(141)
Derivative instruments	**(74)**	–
Income taxes recoverable through future rates	**(187)**	(181)
Investments	**(31)**	—
Prepaid pension costs	**–**	(16)
Other	**(65)**	(65)
Total deferred income tax liabilities	**(1,960)**	(1,984)
Total net deferred income tax liabilities	**$ (84)**	$ (417)

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

(in millions)	2005	2004
Current deferred income tax assets	**$ 50**	$ 112
Noncurrent deferred income tax assets, included in other assets and deferred debits	**30**	14
Current deferred income tax liabilities, included in other current liabilities	**(1)**	–
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(163)**	(543)
Total net deferred income tax liabilities	**$ (84)**	$ (417)

Total noncurrent income tax liabilities on the Consolidated Balance Sheets at December 31, 2005 and 2004 include $115 million and $105 million, respectively, related to probable tax liabilities on which we accrue interest that would be payable with the related tax amount in future years.

At December 31, 2005, the federal income tax credit carry forward includes $925 million of alternative minimum tax credits that do not expire and $32 million of general business credits that will expire during the period 2022 through 2025. The alternative minimum tax credit carry forward at December 31, 2005, includes $3 million that would be limited if a change in ownership were to occur with respect to certain indirect wholly owned subsidiary companies.

At December 31, 2005, we had gross state net operating loss carry forwards of $901 million that will expire during the period 2009 through 2024.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We established additional valuation allowances of $14 million during 2005. We believe it is more likely than not that the results of future operations will generate sufficient taxable income to allow for the utilization of the remaining deferred tax assets.

We establish accruals for certain tax contingencies when, despite our belief that our tax return positions are fully supported, we believe that certain positions may be challenged and that it is probable our positions may not be fully sustained. We are under continuous examination by the IRS and other tax authorities and we account for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2005 and 2004, we had recorded $60 million of tax contingency reserves, excluding accrued interest and penalties, which were included in other current liabilities on the Consolidated Balance Sheets.

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

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

	2005	2004	2003
Effective income tax rate	**(6.8)%**	12.9%	(16.2)%
State income taxes, net of federal benefit	**(3.4)**	(6.9)	(3.8)
Minority interest	**(1.9)**	(1.0)	0.1
Federal tax credits	**43.6**	26.7	50.6
Investment tax credit amortization	**2.0**	1.7	2.3
Employee stock ownership plan dividends	**1.9**	1.8	2.1
Domestic manufacturing deduction	**1.3**	–	–
Other differences, net	**(1.7)**	(0.2)	(0.1)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

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

(in millions)	**2005**	2004	2003
Current – federal	**$ 351**	$238	$297
– state	**75**	72	57
Deferred – federal	**(137)**	14	(86)
– state	**(32)**	16	(19)
State net operating loss carry forward	**(6)**	(5)	–
Synthetic fuel tax credit	**(283)**	(215)	(346)
Investment tax credit	**(13)**	(14)	(16)
Total income tax expense (benefit)	**$ (45)**	$106	$(113)

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

- Less than $1 million of deferred tax expense and $16 million of deferred tax benefit related to the cumulative effect of changes in accounting principle recorded net of tax during 2005 and 2003, respectively. There was no cumulative effect of changes in accounting principle recorded during 2004.
- Taxes related to discontinued operations recorded net of tax for 2005, 2004 and 2003, which are presented separately in Notes 3A and 3B.
- Taxes related to other comprehensive income recorded net of tax for 2005, 2004 and 2003, which are presented separately in the Consolidated Statements of Comprehensive Income.
- Current tax benefit of $2 million related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005. Less than $1 million was recorded in common stock for excess tax deductions during 2004. There was no amount recorded in common stock for excess tax deductions during 2003.

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity that owns facilities that produce synthetic fuel as defined under the Code. The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29/45K if certain requirements are satisfied (See Note 23D).

PEC

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

(in millions)	2005	2004
Deferred income tax assets:		
Asset retirement obligation liability	**$ 131**	$ 137
Compensation accruals	**46**	49
Deferred revenue	**55**	-
Income taxes refundable through future rates	**54**	49
Postretirement and pension benefits	**155**	136
Other	**49**	80
Federal income tax credit carry forward	**20**	20
Total deferred income tax assets	**510**	471
Deferred income tax liabilities:		
Accumulated depreciation and property cost differences	**(952)**	(1,037)
Deferred fuel recovery	**(67)**	(54)
Income taxes recoverable through future rates	**(129)**	(134)
Investments	**(61)**	(59)
Other	**(27)**	(39)
Total deferred income tax liabilities	**(1,236)**	(1,323)
Total net deferred income tax liabilities	**$ (726)**	$ (852)

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

(in millions)	2005	2004
Current deferred income tax assets, included in prepayments and other current assets	**$ –**	$ 36
Current deferred income tax liabilities, included in other current liabilities	**(4)**	–
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(722)**	(888)
Total net deferred income tax liabilities	**$ (726)**	$ (852)

Total noncurrent income tax liabilities on the Consolidated Balance Sheets at December 31, 2005 and 2004 include $92 million and $103 million, respectively, related to probable tax liabilities, on which PEC accrues interest that would be payable with the related tax amount in future years.

At December 31, 2005, the federal income tax credit carry forward includes $20 million of general business credits that will expire during the period 2022 through 2025.

At December 31, 2005 and 2004, PEC had recorded $2 million and less than $1 million, respectively, of tax contingency reserves, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

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

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

	2005	2004	2003
Effective income tax rate	**32.7%**	34.1%	32.3%
State income taxes, net of federal benefit	**(2.1)**	(2.9)	(1.9)
Investment tax credit amortization	**1.1**	1.1	1.4
Domestic manufacturing deduction	**0.7**	–	–
Progress Energy tax benefit allocation	**2.9**	3.0	3.0
Other differences, net	**(0.3)**	(0.3)	0.2
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

(in millions)	**2005**	2004	2003
Current – federal	**$ 343**	$ 232	$ 283
– state	**45**	33	37
Deferred – federal	**(120)**	(18)	(56)
– state	**(21)**	(1)	(13)
Investment tax credit	**(8)**	(7)	(10)
Total income tax expense	**$ 239**	$ 239	$ 241

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

- Less than $1 million of deferred tax expense and $15 million of deferred tax benefit related to the cumulative effect of changes in accounting principle recorded net of tax during 2005 and 2003, respectively. There was no cumulative effect of changes in accounting principle recorded during 2004.
- Taxes related to other comprehensive income recorded net of tax for 2005, 2004 and 2003, which are presented separately in the Consolidated Statements of Comprehensive Income.
- Current tax benefit of $1 million related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005. Less than $1 million was recorded in common stock for excess tax deductions during 2004. There was no amount recorded in common stock for excess tax deductions during 2003.

PEC and each of its wholly owned subsidiaries have entered into the Tax Agreement with Progress Energy (See Note 1D). PEC's intercompany tax payable was approximately $74 million at December 31, 2005. PEC's intercompany tax receivable was approximately $62 million at December 31, 2004.

PEF

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

(in millions)	**2005**	2004
Deferred income tax assets		
Asset retirement obligation liability	**$ 3**	$ 32
Income taxes refundable through future rates	**123**	49
Postretirement and pension benefits	**85**	78
Unbilled revenue	**30**	35
Other	**68**	85
Total deferred income tax assets	**309**	279
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(401)**	(403)
Deferred fuel recovery	**(21)**	(13)
Deferred storm costs	**(87)**	(131)
Derivative instruments	**(45)**	(1)
Income taxes recoverable through future rates	**(28)**	(21)
Investments	**(45)**	(38)
Prepaid pension costs	**(61)**	(89)
Other	**(25)**	(30)
Total deferred income tax liabilities	**(713)**	(726)
Total net deferred income tax liabilities	**$ (404)**	$ (447)

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

(in millions)	**2005**	2004
Current deferred income tax assets	**$ 12**	$ 42
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(416)**	(489)
Total net deferred income tax liabilities	**$ (404)**	$ (447)

Total noncurrent income tax liabilities on the Balance Sheets at December 31, 2005 and 2004, include $17 million and less than $1 million, respectively, related to probable tax liabilities on which PEF accrues interest that would be payable with the related tax amount in future years.

At December 31, 2005 and 2004, PEF had recorded $7 million of tax contingency reserves, excluding accrued interest and penalties, which were included in other current liabilities on the Balance Sheets.

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

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

	2005	2004	2003
Effective income tax rate	**31.8%**	34.2%	33.1%
State income taxes, net of federal benefit	**(3.3)**	(3.5)	(3.5)
Investment tax credit amortization	**1.4**	1.2	1.4
Domestic manufacturing deduction	**0.9**	–	–
Progress Energy tax allocation benefit	**3.2**	2.5	2.7
Other differences, net	**1.0**	0.6	1.3
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

(in millions)	**2005**	2004	2003
Current – federal	**$ 146**	$ 55	$ 145
– state	**25**	9	27
Deferred – federal	**(39)**	98	(16)
– state	**(6)**	18	(3)
Investment tax credit	**(5)**	(6)	(6)
Total income tax expense (benefit)	**$ 121**	$ 174	$ 147

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

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2004 or 2003.
- Taxes related to other comprehensive income recorded net of tax for 2005, 2004 and 2003, which are presented separately in the Statements of Comprehensive Income.
- Less than $1 million of current tax benefit related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005 and 2004. There was no amount recorded in common stock for excess tax deductions during 2003.

PEF has entered into the Tax Agreement with Progress Energy (See Note 1D) and its intercompany tax payable was approximately $7 million and $21 million at December 31, 2005 and 2004, respectively.

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million contingent value obligations (CVOs). Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuel facilities purchased by subsidiaries of Florida Progress in October 1999. The payments, if any, would be based on the net after-tax cash flows the facilities generate. The CVO liability is adjusted to reflect market price fluctuations. The unrealized loss/gain recognized due to these market fluctuations is recorded in other, net on the Consolidated Statements of Income (See Note 21). The liability, included in other liabilities and deferred credits, at December 31, 2005 and 2004, was $7 million and $13 million, respectively.

16. BENEFIT PLANS

A. Postretirement Benefits

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

COSTS OF BENEFIT PLANS

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

To determine the market-related value of assets, we use a five-year averaging method for a portion of its 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)	**2005**	2004	2003	**2005**	2004	2003
Service cost	**$ 47**	$ 54	$ 52	**$ 9**	$ 12	$ 15
Interest cost	**117**	110	108	**33**	31	33
Expected return on plan assets	**(147)**	(155)	(144)	**(5)**	(5)	(4)
Amortization of actuarial loss	**35**	21	25	**8**	4	5
Other amortization, net	**1**	–	–	**1**	1	4
Net periodic cost	**53**	30	41	**46**	43	53
Additional cost (benefit) recognition (a)	**(15)**	(16)	(18)	**2**	2	2
Net periodic cost recognized	**$ 38**	$ 14	$ 23	**$ 48**	$ 45	$ 55

(a) Relates to the acquisition of Florida Progress (See Note 16B).

In addition to the net periodic cost reflected above, in 2005, we recorded costs for special termination benefits related to the voluntary enhanced retirement program (See Note 17) of $123 million for pension benefits and $19 million for other postretirement benefits. In 2003, we also recorded curtailment and settlement effects related to the disposition of NCNG, which are reflected in income/(loss) from discontinued operations in the Consolidated Statements of Income. These effects included a pension-related loss of $13 million and an OPEB-related gain of $1 million.

PEC

(in millions)	Pension Benefits 2005	2004	2003	Other Postretirement Benefits 2005	2004	2003
Service cost	**$ 22**	$ 24	$ 23	**$ 4**	$ 6	$ 7
Interest cost	**53**	52	51	**17**	15	15
Expected return on plan assets	**(62)**	(69)	(70)	**(4)**	(4)	(3)
Amortization of actuarial loss	**10**	1	–	**5**	2	2
Other amortization, net	**1**	–	–	**1**	1	3
Net periodic cost	**$ 24**	$ 8	$ 4	**$ 23**	$ 20	$ 24

In addition to the net periodic cost reflected above, in 2005, PEC recorded costs for special termination benefits related to the voluntary enhanced retirement program (See Note 17) of $21 million for pension benefits and $8 million for other postretirement benefits.

PEF

(in millions)	Pension Benefits 2005	2004	2003	Other Postretirement Benefits 2005	2004	2003
Service cost	**$ 16**	$ 21	$ 19	**$ 3**	$ 4	$ 5
Interest cost	**48**	43	41	**13**	13	15
Expected return on plan assets	**(73)**	(73)	(58)	**(1)**	(1)	(1)
Amortization of actuarial loss	**8**	2	5	**2**	1	1
Other amortization, net	**(1)**	(1)	(2)	**4**	4	4
Net periodic cost (benefit)	**$ (2)**	$ (8)	$ 5	**$ 21**	$ 21	$ 24

In addition to the net periodic cost and benefit reflected above, in 2005 PEF recorded costs for special termination benefits related to the voluntary enhanced retirement program (See Note 17) of $84 million for pension benefits and $7 million for other postretirement benefits.

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

	Pension Benefits 2005	2004	2003	Other Postretirement Benefits 2005	2004	2003
Discount rate	**5.70%**	6.30%	6.60%	**5.70%**	6.30%	6.60%
Rate of increase in future compensation						
Bargaining	**3.50%**	3.50%	3.50%	–	–	–
Nonbargaining	–	–	4.00%	–	–	–
Supplementary plans	**5.25%**	5.00%	4.00%	–	–	–
Expected long-term rate of return on plan assets	**9.00%**	9.25%	9.25%	**8.25%**	8.50%	8.45%

The weighted-average actuarial assumptions used by PEC and PEF were not materially different from the assumptions above, as applicable, except that the expected long-term rate of return on PEF's OPEB plan assets was 5.0% for all years presented.

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

PREPAID/ACCRUED BENEFIT COSTS

Reconciliations of the changes in the Progress Registrants' benefit obligations and the funded status follow:

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2005**	2004	**2005**	2004
Projected benefit obligation at January 1	**$ 1,961**	$ 1,772	**$ 538**	$ 472
Service cost	**47**	54	**9**	12
Interest cost	**117**	110	**33**	31
Benefit payments	**(182)**	(98)	**(33)**	(23)
Plan amendment	**–**	21	**–**	–
Special termination benefits	**123**	–	**19**	–
Actuarial loss (gain)	**98**	102	**84**	46
Obligation at December 31	**2,164**	1,961	**650**	538
Fair value of plan assets at December 31	**1,770**	1,774	**76**	70
Funded status	**(394)**	(187)	**(574)**	(468)
Unrecognized transition obligation	**–**	–	**9**	10
Unrecognized prior service cost	**23**	24	**5**	6
Unrecognized net actuarial loss	**570**	530	**170**	94
Minimum pension liability adjustment	**(546)**	(470)	**–**	–
Accrued cost at December 31, net (See Note 16B)	**$ (347)**	$ (103)	**$ (390)**	$ (358)

The net accrued pension cost of $347 million at December 31, 2005, is included in accrued pension and other benefits in the Consolidated Balance Sheets. The net accrued pension cost of $103 million at December 31, 2004, is recognized in the Consolidated Balance Sheets as prepaid pension cost of $42 million and accrued benefit cost of $145 million, which is included in accrued pension and other benefits. The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $2.16 and $1.72 billion at December 31, 2005 and 2004, respectively. Those plans had accumulated benefit obligations totaling $2.12 and $1.71 billion at December 31, 2005 and 2004, respectively, and plan assets of $1.77 and $1.57 billion at December 31, 2005 and 2004, respectively. The total accumulated benefit obligation for pension plans was $2.12 and $1.90 billion at December 31, 2005 and 2004, respectively. The accrued OPEB cost is included in accrued pension and other benefits in the Consolidated Balance Sheets.

A minimum pension liability adjustment of $546 million was recorded at December 31, 2005. This adjustment resulted in a charge of $23 million to intangible assets, a $180 million charge to a pension-related regulatory liability (See Note 16B), an $83 million charge to a regulatory asset pursuant to an FPSC order and a pre-tax charge of $260 million to accumulated other comprehensive loss, a component of common stock equity. A minimum pension liability adjustment of $470 million was recorded at December 31, 2004. This adjustment resulted in a charge of $24 million to intangible assets, a $150 million charge to a pension-related regulatory liability (See Note 16B), a $67 million charge to a regulatory asset pursuant to an FPSC order and a pre-tax charge of $229 million to accumulated other comprehensive loss, a component of common stock equity.

PEC

(in millions)	Pension Benefits 2005	Pension Benefits 2004	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004
Obligation at January 1	**$ 928**	$ 837	**$ 262**	$ 218
Service cost	**22**	24	**4**	6
Interest cost	**53**	52	**17**	15
Plan amendment	–	14	–	–
Benefit payments	**(94)**	(50)	**(14)**	(5)
Actuarial loss (gain)	**39**	51	**56**	28
Special termination benefits	**21**	–	**8**	–
Obligation at December 31	**969**	928	**333**	262
Fair value of plan assets at December 31	**731**	753	**49**	45
Funded status	**(238)**	(175)	**(284)**	(217)
Unrecognized transition obligation	–	–	**8**	9
Unrecognized prior service cost	**17**	18	–	–
Unrecognized net actuarial (gain) loss	**201**	181	**87**	36
Minimum pension liability adjustment	**(212)**	(194)	–	–
Accrued cost at December 31, net	**$ (232)**	$ (170)	**$ (189)**	$ (172)

The net accrued pension cost of $232 and $170 million at December 31, 2005 and 2004, respectively, is included in accrued pension and other benefits in the Consolidated Balance Sheets. The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $969 and $928 million at December 31, 2005 and 2004, respectively. Those plans had accumulated benefit obligations totaling $963 and $923 million, at December 31, 2005 and 2004, respectively, and plan assets of $731 and $753 million at December 31, 2005 and 2004, respectively. The total accumulated benefit obligation for pension plans was $963 and $923 million at December 31, 2005 and 2004, respectively. The accrued OPEB cost is included in accrued pension and other benefits in the Consolidated Balance Sheets.

A minimum pension liability adjustment of $212 million was recorded at December 31, 2005. This adjustment resulted in a charge of $17 million to intangible assets, included in other assets and deferred debits, and a pre-tax charge of $195 million to accumulated other comprehensive loss, a component of common stock equity. A minimum pension liability adjustment of $194 million was recorded at December 31, 2004. This adjustment resulted in a charge of $18 million to intangible assets, included in other assets and deferred debits, and a pre-tax charge of $176 million to accumulated other comprehensive loss, a component of common stock equity.

PEF

(in millions)	Pension Benefits 2005	Pension Benefits 2004	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004
Obligation at January 1	**$ 767**	$ 701	**$ 232**	$ 217
Service cost	**16**	21	**3**	4
Interest cost	**48**	43	**13**	13
Plan amendment	**–**	2	**–**	–
Benefit payments	**(61)**	(37)	**(18)**	(17)
Special termination benefits	**85**	–	**7**	–
Actuarial loss (gain)	**41**	37	**22**	15
Obligation at December 31	**896**	767	**259**	232
Fair value of plan assets at December 31	**895**	868	**22**	20
Funded status	**(1)**	101	**(237)**	(212)
Unrecognized transition obligation	**–**	–	**24**	27
Unrecognized prior service cost (benefit)	**(12)**	(14)	**5**	6
Unrecognized net actuarial (gain) loss	**132**	112	**49**	29
Minimum pension liability adjustment	**(8)**	(7)	**–**	–
Prepaid (accrued) cost at December 31, net	**$ 111**	$ 192	**$ (159)**	$ (150)

The PEF net prepaid pension cost of $111 and $192 million at December 31, 2005 and 2004, respectively, is included in the Balance Sheets as prepaid pension cost of $200 million and $234 million, respectively, and accrued benefit cost of $89 million and $42 million, respectively, which is included in accrued pension and other benefits. The PEF defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $341 and $41 million at December 31, 2005 and 2004, respectively. Those plans had accumulated benefit obligations totaling $306 million and $39 million, respectively, and plan assets of $217 million at December 31, 2005, and no plan assets at December 31, 2004. PEF's total accumulated benefit obligation for pension plans was $860 million and $718 million at December 31, 2005 and 2004, respectively. Accrued other postretirement benefit cost is included in accrued pension and other benefits in PEF's Balance Sheets.

PEF recorded a minimum pension liability adjustment of $8 million at December 31, 2005. This adjustment resulted in a charge of $1 million to intangible assets, included in other assets and deferred debits, and a charge of $7 million to a regulatory asset. PEF recorded a minimum pension liability adjustment of $7 million at December 31, 2004, with a corresponding charge of $7 million to a regulatory asset.

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

	Pension Benefits 2005	Pension Benefits 2004	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004
Discount rate	**5.65%**	5.90%	**5.65%**	5.90%
Rate of increase in future compensation				
Bargaining	**3.50%**	3.50%	**–**	–
Supplementary plans	**5.25%**	5.25%	**–**	–
Initial medical cost trend rate for pre-Medicare Act benefits	**–**	–	**8.25%**	7.25%
Initial medical cost trend rate for post-Medicare Act benefits	**–**	–	**8.25%**	7.25%
Ultimate medical cost trend rate	**–**	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	**–**	–	**2013**	2008

The weighted-average actuarial assumptions for PEC and PEF were the same or were not significantly different from those indicated above, as applicable.

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	$ 5	$ 2	$ 2
Effect on postretirement benefit obligation	65	33	26
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(4)	(2)	(2)
Effect on postretirement benefit obligation	(54)	(28)	(22)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, substantially all employer contributions represent benefit payments made directly from the Progress Registrants' assets except for the 2004 pension amount. The remaining benefit payments were made directly from plan assets. In 2004, we made a required contribution of approximately $24 million directly to pension plan assets. In 2004, PEC made a contribution to pension plan assets of approximately $20 million, which represented its allocated share of the required Progress Energy contribution. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the net cost after participant contributions. Participant contributions represent approximately 20 percent of gross benefit payments for Progress Energy, 30 percent for PEC and 10 percent for PEF.

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

Progress Energy	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2005**	2004	**2005**	2004
Fair value of plan assets at January 1	**$ 1,774**	$ 1,631	**$ 70**	$ 65
Actual return on plan assets	**170**	211	**5**	8
Benefit payments	**(182)**	(98)	**(33)**	(23)
Employer contributions	**8**	30	**34**	20
Fair value of plan assets at December 31	**$ 1,770**	$ 1,774	**$ 76**	$ 70

PEC	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2005**	2004	**2005**	2004
Fair value of plan assets at January 1	**$ 753**	$ 693	**$ 45**	$ 43
Actual return on plan assets	**71**	89	**4**	5
Benefit payments	**(94)**	(50)	**(14)**	(5)
Employer contributions	**1**	21	**14**	2
Fair value of plan assets at December 31	**$ 731**	$ 753	**$ 49**	$ 45

PEF

(in millions)	Pension Benefits 2005	Pension Benefits 2004	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004
Fair value of plan assets at January 1	**$ 868**	$ 802	**$ 20**	$ 18
Actual return on plan assets	**85**	101	**–**	1
Benefit payments	**(61)**	(37)	**(18)**	(17)
Employer contributions	**3**	2	**19**	18
Fair value of plan assets at December 31	**$ 895**	$ 868	**$ 21**	$ 20

The asset allocation for the benefit plans at the end of 2005 and 2004 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	2006	**2005**	2004
Equity – domestic	40%	**44%**	47%
Equity – international	15%	**22%**	21%
Debt – domestic	20%	**13%**	9%
Debt – international	10%	**8%**	11%
Other	15%	**13%**	12%
Total	100%	**100%**	100%

	Other Postretirement Benefits		
Progress Energy	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2006	**2005**	2004
Equity – domestic	28%	**32%**	34%
Equity – international	11%	**16%**	15%
Debt – domestic	43%	**37%**	35%
Debt – international	7%	**6%**	8%
Other	11%	**9%**	8%
Total	100%	**100%**	100%

PEC	Target Allocations	Percentage of Plan Assets	
Asset Category	2006	**2005**	2004
Equity – domestic	40%	**44%**	47%
Equity – international	15%	**22%**	21%
Debt – domestic	20%	**13%**	9%
Debt – international	10%	**8%**	11%
Other	15%	**13%**	12%
Total	100%	**100%**	100%

PEF	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2006	**2005**	2004
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 2006, we expect to make $10 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 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $164, $124, $127, $133, $137 and $789, respectively. The expected benefit payments for the OPEB plan for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $41, $43, $45, $46, $48 and $245, 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. We expect to begin receiving prescription drug-related federal subsidies in 2006, and the expected subsidies for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $3, $3, $3, $4, $4 and $30, respectively.

In 2006, PEC expects to make $1 million in contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $79, $56, $58, $62, $64 and $383, respectively. The expected benefit payments for the OPEB plan for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $19, $20, $21, $22, $23, and $128, 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. PEC expects to begin receiving prescription drug-related federal subsidies in 2006, and the expected subsidies for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $1, $1, $2, $2, $2 and $15, respectively.

In 2006, PEF expects to make $9 million of contributions to pension plan assets and $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $63, $53, $53, $54, $54 and $295, respectively. The expected benefit payments for the OPEB plan for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $19, $20, $20, $20, $20 and $96, 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. PEF expects to begin receiving prescription drug-related federal subsidies in 2006, and the expected subsidies for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $1, $2, $2, $2, $2 and $13, 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. Accordingly, a portion of the accrued OPEB cost reflected in the Progress Energy table above has a corresponding regulatory asset at December 31, 2005, and 2004 (See Note 7A). As indicated in the Progress Energy minimum pension adjustment information, a pension-related regulatory liability was charged, and fully eliminated, at December 31, 2005. At December 31, 2004, a portion of the Progress Energy prepaid pension cost has a corresponding regulatory liability (See Note 7A). Pursuant to its rate treatment, PEF recognized additional periodic pension credits and additional periodic OPEB costs, as indicated in the Progress Energy net periodic cost information above.

17. SEVERANCE

On February 28, 2005, we approved a workforce restructuring that resulted in a reduction of approximately 450 positions. The cost-management initiative is designed to permanently reduce by $75 million to $100 million our projected growth in annual O&M expenses by the end of 2007. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program. In connection with this initiative, we incurred approximately $164 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005, as described below. The workforce restructuring concluded on December 1, 2005.

Progress Energy

We recorded $31 million of severance expense during the first quarter of 2005 for the workforce restructuring and implementation of an automated meter reading initiative at PEF based on the approximate number of positions to be eliminated. During the second quarter of 2005, 1,447 employees eligible for participation in the voluntary enhanced retirement program elected to participate. Consequently, in the second and fourth quarters of 2005, we decreased our estimated severance costs by $13 million each quarter due to the impact of the employees electing participation in the voluntary enhanced retirement program. The severance expenses are primarily included in O&M expense on the Consolidated Statements of Income.

The accrued severance expense will be paid over time. The activity in the severance liability was as follows:

(in millions)	
Balance as of January 1, 2005	$ 5
Severance costs accrued	31
Adjustments	(26)
Payments	(4)
Balance at December 31, 2005	**$ 6**

During 2005, we recorded a $141 million charge in the second quarter and a $1 million charge in the third quarter related to postretirement benefits that will be paid over time to eligible employees who elected to participate in the voluntary enhanced retirement program (See Note 16). In addition, we recorded a $17 million charge for early retirement incentives to be paid over time to certain employees.

PEC

In connection with the cost-management initiative, PEC incurred approximately $55 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005, as described below.

PEC recorded $14 million of severance expense during the first quarter of 2005 for the workforce restructuring based on the approximate number of positions to be eliminated. This amount included approximately $4 million of severance costs allocated from PESC. During the second quarter of 2005, 553 PEC employees eligible for participation in the voluntary enhanced retirement program elected to participate. Consequently, in the second and fourth quarters of 2005, PEC decreased its estimated severance costs by $6 million and $5 million, respectively, due to the impact of the employees electing participation in the voluntary enhanced retirement program. These amounts included approximately $2 million of decreased severance costs allocated from PESC. The severance expenses are primarily included in O&M expense on the Consolidated Statements of Income.

The accrued severance expense will be paid over time. The activity in the severance liability was as follows:

(in millions)	
Balance as of January 1, 2005	$ 2
Severance costs accrued	10
Adjustments	(9)
Payments	(1)
Balance at December 31, 2005	**$ 2**

PEC recorded a $29 million charge in the second quarter of 2005 related to postretirement benefits that will be paid over time to eligible employees who elected to participate in the voluntary enhanced retirement program (See Note 16). PEC also recorded a $13 million charge for early retirement incentives which will be paid over time to certain employees. In addition, PEC recorded approximately $10 million of postretirement benefits and early retirement incentives allocated from PESC during the year ended December 31, 2005.

PEF

In connection with the cost-management initiative, PEF incurred approximately $102 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005, as described below.

PEF recorded $14 million of severance expense during the first quarter of 2005 for the workforce restructuring and implementation of an automated meter reading initiative at PEF based on the approximate number of positions to be eliminated. This amount included approximately $3 million of severance costs allocated from PESC. During the second quarter of 2005, 680 of PEF's employees eligible for participation in the voluntary enhanced retirement program elected to participate. Consequently, in the second and fourth quarters of 2005, PEF decreased its estimated severance costs by $5 million and $6 million, respectively, due to the impact of the employees electing participation in the voluntary enhanced retirement program. These amounts included approximately $2 million of decreased severance costs allocated from PESC. The severance expenses are primarily included in O&M expense on the Statements of Income.

The accrued severance expense will be paid over time. The activity in the severance liability was as follows:

(in millions)	
Balance as of January 1, 2005	$ –
Severance costs accrued	11
Adjustments	(9)
Payments	(1)
Balance at December 31, 2005	**$ 1**

During 2005, PEF recorded a $90 million charge in the second quarter and a $1 million charge in the third quarter related to postretirement benefits that will be paid over time to eligible employees who elected to participate in the voluntary enhanced retirement program (See Note 16). In addition, PEF recorded approximately $8 million of charges for postretirement benefits and early retirement incentives allocated from PESC during the year ended December 31, 2005.

18. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

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

A. Commodity Derivatives

GENERAL

Most of our commodity contracts are not derivatives pursuant to SFAS No. 133, "Accounting for Derivative and Hedging Activities" (SFAS No. 133), or do not 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 21). At December 31, 2005 and 2004, the remaining liability was $19 million and $26 million, respectively.

ECONOMIC DERIVATIVES

Derivative products, primarily electricity and natural gas contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material to our or the Utilities' results of operations during 2005, 2004 and 2003. PEC did not have material outstanding positions in such contracts at December 31, 2005 and 2004. We and PEF did not have material outstanding positions in such contracts at December 31, 2005 and 2004, other than those receiving regulatory accounting treatment at PEF, as discussed below.

PEF has derivative instruments related to its exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, until the contracts are settled. Once settled, any realized gains or losses are passed through the fuel clause. At December 31, 2005, the fair values of the instruments were a $77 million short-term derivative asset position included in other current assets, a $45 million long-term derivative asset position included in other assets and deferred debits and a $6 million long-term derivative liability position included in other liabilities and deferred credits. At December 31, 2004, the fair values of the instruments were a $2 million long-term derivative asset position included in other assets and deferred debits and a $5 million short-term derivative liability position included in other current liabilities.

CASH FLOW HEDGES

Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of natural gas and power for our forecasted purchases and sales. Realized gains and losses are recorded net in operating revenues or operating expenses, as appropriate. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities' results of operations for 2005, 2004 and 2003.

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

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Fair value of assets	**$ 170**	$ –	**$ 7**	$ –	**$ –**	$ –
Fair value of liabilities	**(58)**	(15)	**(4)**	$ –	**$ –**	$ –
Fair value, net	**$ 112**	$ (15)	**$ 3**	$ –	**$ –**	$ –

The following table presents selected information related to commodity cash flow hedges at December 31, 2005:

(term in years/ millions of dollars)	Maximum Term(a)			Accumulated Other Comprehensive Income/ (Loss), net of Tax			Portion Expected to be Reclassified to Earnings during the Next 12 Months(b)		
	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF
Commodity cash flow hedges	9	1	–	$ 69	$ 2	$ –	$ (17)	$ 2	$ –

(a) The majority of hedges in fair value liability positions are currently classified as short-term and the majority of hedges in fair value asset positions are currently classified as long-term.

(b) Due to the volatility of the commodities markets, the value in accumulated other comprehensive income/(loss) (OCI) is subject to change prior to its reclassification into earnings.

At December 31, 2004, we had $9 million of after-tax deferred losses in OCI related to commodity cash flow hedges. The Utilities had no open commodity cash flow hedges or amounts recorded in OCI related to commodity cash flow hedges.

B. Interest Rate Derivatives – Fair Value or Cash Flow Hedges

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

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

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Interest rate cash flow hedges	**$ 1**	$ (2)	**$ –**	$ (2)	**$ –**	$ –
Interest rate fair value hedges	**$ (2)**	$ 3	**$ –**	$ –	**$ –**	$ –

CASH FLOW HEDGES

Gains and losses from cash flow hedges are recorded in OCI and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. Amounts in OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The ineffective portion of interest rate cash flow hedges was not material to our or the Utilities' results of operations for 2005, 2004 and 2003.

The following table presents selected information related to interest rate cash flow hedges included in OCI at December 31, 2005:

(term in years/ millions of dollars)	Maximum Term			Accumulated Other Comprehensive Income/ (Loss), net of Tax (a)			Portion Expected to be Reclassified to Earnings during the Next 12 Months (b)		
	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF
Interest rate cash flow hedges	1	–	–	$ (13)	$ (5)	$ –	$ (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, 2005 and 2004, we had $100 million notional and $331 million notional, respectively, of interest rate cash flow hedges. The Utilities had no open interest rate cash flow hedges at December 31, 2005. At December 31, 2004, PEC had $131 million notional of open interest rate cash flow hedges and PEF had no open interest rate cash flow hedges.

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, 2005 and 2004, we had $150 million notional of interest rate fair value hedges. At December 31, 2005 and 2004, the Utilities had no open interest rate fair value hedges.

At December 31, 2005 and 2004, we had a $2 million loss and a $9 million gain, respectively, of basis adjustments in long-term debt related to terminated interest rate fair value hedges, which are being amortized over periods ending in 2006 through 2008 coinciding with the maturities of the related debt instruments.

19. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit, surety bonds and guarantees in support of nuclear decommissioning. At December 31, 2005, the Parent had issued $1.56 billion of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 24). 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 PUHCA. The repeal of PUHCA effective February 8, 2006, and subsequent regulation by the FERC is not anticipated to 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 2005, 2004 and 2003 to PEC amounted to $202 million, $209 million and $184 million, respectively, and services provided to PEF were $169 million, $165 million and $153 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2005, 2004 and 2003 amounted to $54 million, $52 million and $35 million, respectively. Services provided by PEF to PEC during 2005, 2004 and 2003 amounted to $14 million, $16 million and $7 million, respectively.

At December 31, 2005, the Parent's guarantees include $169 million to support nuclear decommissioning. PEC determined that its external funding levels did not fully meet the nuclear decommissioning financial assurance levels required by the NRC; therefore, PEC obtained the Parent's guarantee.

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 3.77%, 1.72% and 1.47% at December 31, 2005, 2004 and 2003, 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.

Strategic Resource Solutions Corp. and its subsidiary, which were wholly owned until 2004, managed subcontracts for PEC. Amounts for 2004 and 2003 were not significant.

Progress Fuels sells coal to PEF for an insignificant profit. 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, of $402 million, $331 million and $347 million for the years ended December 31, 2005, 2004 and 2003, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income. Beginning in 2006, PEF will enter into coal contracts on its own behalf.

We sold NCNG to Piedmont Natural Gas Company, Inc. on September 30, 2003 (See Note 3H). Prior to disposition, NCNG sold natural gas to affiliates. During the year ended December 31, 2003, gas sales from NCNG to PEC amounted to $11 million. The gas sales for 2003 indicated above exclude any sales subsequent to September 2003. These revenues are included in discontinued operations on the Consolidated Statements of Income.

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

20. FINANCIAL INFORMATION BY BUSINESS SEGMENT

Our reportable segments are: PEC, PEF, Progress Ventures and Coal and Synthetic Fuels. During 2005, we realigned our segments due to changes in the operations of certain businesses and the reclassification of our coal mining business to discontinued operations. These changes are consistent with the manner in which management currently reviews our operations. Prior year periods have been restated for our segment realignments.

Our PEC and PEF business segments are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. Prior to December 2005, we disclosed a PEC Electric segment that was comprised of utility operations and excluded immaterial operations of PEC's nonregulated subsidiaries, which were included in Corporate and Other. Management has realigned the PEC segment to review the PEC operations on a consolidated basis as the results of operations and financial position are not materially different between PEC Electric and PEC.

Our Progress Ventures segment is comprised of Competitive Commercial Operations (CCO) and natural gas operations (Gas) and is involved in nonregulated electric generation and energy marketing activities and natural gas drilling and production in Texas and Louisiana. Prior to December 2005, CCO had been reported as a separate segment and Gas was included within our previously reported Fuels segment. Progress Ventures' legal structure is not currently aligned with the functional management and financial reporting of the Progress Ventures segment.

Our Coal and Synthetic Fuels segment is involved in the production and sale of coal-based solid synthetic fuel as defined under the Code, coal terminal services, and fuel transportation and delivery. Operations involving coal terminals and synthetic fuels activities were included within our previously reported Fuels segment prior to 2005. The remaining portions of our previously reported Fuels segment are included within Coal and Synthetic Fuels due to their operational relationship with the segment's activities and their relative immateriality.

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

Prior to its divestiture in 2005, Rail Services was reported as a separate segment (See Note 3B). The operations of Rail Services were reclassified to discontinued operations in the first quarter of 2005. During the fourth quarter of 2005, we reclassified our coal mining operations as discontinued operations (See Note 3A). Prior to 2005, our coal mining operations were included within our previously reported Fuels segment. Our Rail Services and coal mining operations are not included in the results from continuing operations during the periods reported. Assets and capital and investment expenditures of discontinued operations are not included in the tables presented below.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between PEF and the Coal and Synthetic Fuel segment, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and the Coal and Synthetic Fuel 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 2005, 2004 and 2003 were not significant. Income tax expense (benefit) by segment includes the Parent's allocation to profitable subsidiaries of income tax benefits not related to acquisition interest expense in accordance with the Tax Agreement. Due to the repeal of PUHCA, the Parent will stop allocating these tax benefits in 2006.

In the following tables, capital and investment expenditures include property additions, acquisitions of nuclear fuel and other capital investments.

(in millions)	PEC	PEF	Progress Venture Venturs	Coal and Synthetic Fuels	Corporate and Other	Eliminations	Totals
Year ended December 31, 2005							
Revenues							
Unaffiliated	**$ 3,991**	**$ 3,955**	**$ 853**	**$ 1,242**	**$ 67**	**$ –**	**$ 10,108**
Intersegment	**–**	**–**	**–**	**402**	**447**	**(849)**	**–**
Total revenues	**3,991**	**3,955**	**853**	**1,644**	**514**	**(849)**	**10,108**
Depreciation and amortization	**561**	**334**	**94**	**38**	**47**	**–**	**1,074**
Total interest charges, net	**192**	**126**	**5**	**34**	**372**	**(89)**	**640**
Postretirement and severance charges	**55**	**102**	**1**	**5**	**1**	**–**	**164**
Impairment of long-lived assets and investments	**(1)**	**–**	**–**	**–**	**–**	**–**	**(1)**
Income tax expense (benefit)	**239**	**121**	**7**	**(350)**	**(62)**	**–**	**(45)**
Segment profit (loss)	**490**	**258**	**21**	**169**	**(211)**	**–**	**727**
Total assets	**11,502**	**8,318**	**2,371**	**472**	**18,024**	**(13,773)**	**26,914**
Capital and investment expenditures	**682**	**543**	**183**	**16**	**29**	**(19)**	**1,434**
Year ended December 31, 2004							
Revenues							
Unaffiliated	$ 3,629	$ 3,525	$ 401	$ 899	$ 71	$ –	$ 8,525
Intersegment	–	–	–	331	440	(771)	–
Total revenues	3,629	3,525	401	1,230	511	(771)	8,525
Depreciation and amortization	570	281	101	38	45	–	1,035
Total interest charges, net	192	114	11	37	360	(86)	628
Postretirement and severance charges	2	–	–	1	–	–	3
Income tax expense (benefit)	239	174	55	(280)	(82)	–	106
Segment profit (loss)	458	333	81	88	(231)	–	729
Total assets	10,787	7,924	2,086	542	17,590	(13,570)	25,359
Capital and investment expenditures	620	492	154	10	26	(12)	1,290
Year ended December 31, 2003							
Revenues							
Unaffiliated	$ 3,600	$ 3,152	$ 285	$ 716	$ 46	$ –	$ 7,799
Intersegment	–	–	–	347	440	(787)	–
Total revenues	3,600	3,152	285	1,063	486	(787)	7,799
Depreciation and amortization	562	307	78	35	27	–	1,009
Total interest charges, net	197	91	6	29	378	(94)	607
Impairment of long-lived assets and investments	(21)	–	–	–	–	–	(21)
Income tax expense (benefit)	241	147	25	(434)	(47)	(45)	(113)
Segment profit (loss)	502	295	54	190	(230)	–	811
Total assets	10,938	7,280	2,195	599	17,802	(13,368)	25,446
Capital and investment expenditures	511	577	606	24	19	–	1,737

21. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income, impairment of investments, and other income and expense items as discussed below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities. AFUDC equity represents the estimated equity costs of capital funds necessary to finance the construction of new regulated assets. The components of other, net as shown on the accompanying Statements of Income for the years ended December 31 were as follows:

Progress Energy

(in millions)	**2005**	2004	2003
Other income			
Nonregulated energy and delivery services income	**$ 32**	$ 28	$ 26
DIG Issue C20 amortization (Note 18A)	**7**	9	2
Contingent value obligation unrealized gain (Note 15)	**6**	9	–
Investment gains	**7**	4	12
Income from equity investments	**1**	3	–
AFUDC equity	**16**	12	14
Other	**15**	13	15
Total other income	**84**	78	69
Other expense			
Nonregulated energy and delivery services expenses	**24**	21	20
Donations	**18**	15	15
Investment losses	**–**	1	6
Contingent value obligation unrealized loss (Note 15)	**–**	–	9
Loss from equity investments	**7**	8	31
Loss on debt extinguishment and interest rate collars	**–**	15	–
FERC audit settlement	**7**	–	–
Indemnification liability (Note 22B)	**16**	–	–
Other	**17**	30	15
Total other expense	**89**	90	96
Other, net – Progress Energy	**$ (5)**	$ (12)	$ (27)

PEC

(in millions)	**2005**	2004	2003
Other income			
Nonregulated energy and delivery services income	**$ 12**	$ 11	$ 12
DIG Issue C20 amortization (Note 18A)	**7**	9	2
Income from equity investments	**1**	3	–
AFUDC equity	**3**	4	2
Other	**10**	13	2
Total other income	**33**	40	18
Other expense			
Nonregulated energy and delivery services expenses	**$ 9**	$ 9	$ 9
Donations	**8**	7	6
Losses from equity investments	**–**	3	16
FERC audit settlement	**4**	–	–
Indemnification liability (Note 22B)	**16**	–	–
Other	**10**	22	6
Total other expense	**47**	41	37
Other, net – PEC	**$ (14)**	$ (1)	$ (19)

PEF

(in millions)	**2005**	2004	2003
Other income			
Nonregulated energy and delivery services income	**$ 20**	$ 17	$ 15
Investment gains	**2**	1	2
AFUDC equity	**13**	7	12
Total other income	**35**	25	29
Other expense			
Nonregulated energy and delivery services expenses	**14**	12	11
Donations	**10**	9	9
FERC audit settlement	**3**	–	–
Other	**1**	1	2
Total other expense	**28**	22	22
Other, net – PEF	**$ 7**	$ 3	$ 7

22. ENVIRONMENTAL MATTERS

We are subject to federal, state and local regulations addressing hazardous and solid waste management, air and water quality and other environmental matters.

A. Hazardous and Solid Waste Management

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina or the state of Florida, as described below in greater detail. Various 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 potentially responsible parties (PRPs) at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. A discussion of sites by legal entity follows below.

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.

PEC and PEF filed claims with general liability insurance carriers to recover costs arising from actual or potential environmental liabilities for remediation of certain sites. No material claims are currently pending. We may file further claims with respect to sites for which claims were not previously presented.

Progress Energy

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

In 2001, we, through our Progress Fuels subsidiary, established an accrual to address indemnities and retained an environmental liability associated with the sale of our Inland Marine Transportation business. In 2003, the accrual was reduced to $4 million based on a change in estimate. At December 31, 2005 and 2004, the remaining accrual balance was approximately $3 million. Expenditures related to this liability were not material to our financial condition during 2005 and 2004.

We are voluntarily addressing certain historical sites. An immaterial accrual has been established to address investigation expenses related to these sites. At this time, the total costs that may be incurred in connection with these sites cannot be determined.

On March 24, 2005, we completed the sale of our Progress Rail subsidiary. In connection with the sale, we incurred indemnity obligations related to certain pre-closing liabilities, including certain environmental matters (See discussion under Guarantees in Note 23C).

PEC

There are nine former MGP sites and a number of other sites associated with PEC that have required or are anticipated to require investigation and/or remediation.

In September 2005, the EPA advised PEC that it had been identified as a PRP at the Carolina Transformer site located in Fayetteville, N.C. The EPA offered PEC and a number of other PRPs the opportunity to share the reimbursement of approximately $36 million to the EPA for past expenditures in addressing conditions at the site. Although a loss is considered probable, an agreement among PRPs has not been reached; consequently, it is not possible at this time to reasonably estimate the total amount of PEC's obligation for remediation of the Carolina Transformer site. PEC may file claims with respect to this site. The outcome of this matter cannot be predicted.

During the fourth quarter of 2004, the EPA advised PEC that it had been identified as a PRP at the Ward Transformer site located in Raleigh, N.C. The EPA offered PEC and a number of other PRPs the opportunity to negotiate cleanup of the site and reimbursement to the EPA for EPA's past expenditures in addressing conditions at the site. In September 2005, PEC and several other PRPs signed a settlement agreement, which requires the participating PRPs to provide approximately $5 million to cover the cleanup cost and repay less than $1 million of EPA's past costs. PEC has accrued its portion of these estimated costs. Based upon additional assessment work performed at the site during the first quarter of 2006, it is probable that additional costs beyond the EPA's original cost estimate will be incurred. However, the range of additional losses cannot be determined at this time. PEC may file claims with respect to this site. The outcome of this matter cannot be predicted.

At December 31, 2005 and 2004, PEC's accruals for probable and estimable costs related to various environmental sites, which are included in other liabilities and deferred credits and are expected to be paid out over one to five years, were $7 million and $9 million, respectively. The amount includes insurance fund proceeds that PEC received to address costs associated with environmental liabilities related to its involvement with some sites. All eligible expenses related to these sites are charged against a specific fund containing these proceeds. During 2005, PEC spent approximately $6 million, accrued approximately $4 million and received no insurance proceeds related to environmental remediation. During 2004, PEC spent approximately $2 million related to environmental remediation.

On March 30, 2005, the North Carolina Division of Water Quality renewed a PEC permit for the continued use of coal combustion products generated at any of its coal-fired plants located in the state. Following review of the permit conditions, which could significantly restrict the reuse of coal ash and result in higher ash management costs, the permit was adjudicated. The outcome of this matter cannot be predicted.

PEF

At December 31, 2005 and 2004, PEF's accruals for probable and estimable costs related to various environmental sites, which were included in other liabilities and deferred credits and are expected to be paid out over one to 15 years, were:

(in millions)	**2005**	2004
Remediation of distribution and substation transformers	**$ 20**	$ 27
MGP and other sites	**18**	18
Total accrual for environmental sites	**$ 38**	$ 45

PEF has received approval from the FPSC for recovery of costs associated with the remediation of distribution and substation transformers through the Environmental Cost Recovery Clause (ECRC). Under agreements with the Florida Department of Environmental Protection (FDEP), PEF is in the process of examining distribution transformer sites and substation sites for potential equipment integrity issues that could result in the need for mineral oil-impacted soil remediation. PEF has reviewed a number of distribution transformer sites and all substation sites. Based on changes to the estimated time frame for review of distribution transformer sites, PEF currently expects to have completed its review by the end of 2007. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC. For the years ended December 31, 2005 and 2004, PEF accrued approximately $2 million and $19 million, respectively, and spent approximately $9 million and $4 million, respectively, related to the remediation of transformers. PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC.

The amounts for MGP and other sites, in the table above, relate to two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation. For the year ended December 31, 2005, PEF made no material accruals, spent approximately $1 million, and received approximately $1 million of additional insurance proceeds. For the year ended December 31, 2004, PEF received approximately $12 million in insurance claim settlement proceeds and recorded a related accrual for associated environmental expenses, as these insurance proceeds are restricted for use in addressing costs associated with environmental liabilities.

In Florida, a risk-based corrective action (RBCA, known as Global RBCA) rule was developed by the FDEP and adopted at the February 2, 2005, Environmental Review Commission hearing. Risk-based corrective action generally means that the corrective action prescribed for contaminated sites can correlate to the level of human health risk imposed by the contamination at the property. The Global RBCA rule expands the use of the risk-based corrective action to all contaminated sites in the state that are not currently in one of the state's waste cleanup programs and has the potential for making future cleanups in Florida more costly to complete. The effective date of the Global RBCA rule was April 17, 2005.

B. Air Quality

We are subject to various current and proposed federal, state and local environmental compliance laws and regulations, which may result in increased planned capital expenditures and O&M expenses. Significant updates to these laws and regulations and related impacts to us since December 31, 2004, are discussed below. Additionally, Congress is considering legislation that would require additional reductions in air emissions of NOx, SO_2, carbon dioxide (CO_2) and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multipollutant approach to air pollution control could involve significant capital costs that could be material to our financial position or results of operations. Control equipment that will be installed on North Carolina coal-fired generating facilities as part of the Clean Smokestacks Act, enacted in 2002 and discussed below, may address some of the issues outlined above as they relate to PEC. However, the outcome of the matter cannot be predicted.

NEW SOURCE REVIEW (NSR)

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants in an effort to determine whether changes at those facilities were subject to NSR requirements or New Source Performance Standards under the Clean Air Act. We were asked to provide information to the EPA as part of this initiative and cooperated in supplying the requested information. The EPA initiated civil enforcement actions against unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements calling for expenditures by these unaffiliated utilities in excess of $1.0 billion. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the companies may seek recovery of the related costs through rate adjustments or similar mechanisms.

On June 24, 2005, the Court of Appeals for the District of Columbia Circuit rendered a decision in a suit regarding EPA's NSR rules. As part of the decision, the court struck down a provision excluding pollution control projects from NSR requirements. As a result of this decision, additional regulatory review of our pollution control equipment proposals will be required, adding time and cost to the overall project.

NO_X SIP CALL RULE UNDER SECTION 110 OF THE CLEAN AIR ACT (NO_X SIP CALL)

The NOx SIP Call is an EPA rule that requires 22 states, including North Carolina, South Carolina and Georgia, to further reduce nitrogen oxide emissions. The NOx SIP Call is not applicable to Florida. Total capital costs to meet the requirements of the final rule under the NOx SIP Call in North Carolina and South Carolina could reach approximately $355 million at PEC, of which approximately $336 million has been incurred through December 31, 2005. This amount also includes the cost to install NOx controls under North Carolina's and South Carolina's programs to comply with the federal eight-hour ozone standard. However, further technical analysis and rulemaking may result in requirements for additional controls at some units. Increased O&M expenses relating to the NOx SIP Call are not expected to be material to our or PEC's results of operations.

Parties unrelated to us have undertaken efforts to have Georgia excluded from the rule and its requirements. Georgia has not yet submitted a state implementation plan to comply with the Section 110 NOx SIP Call. The outcome of this matter and the impact to our nonregulated operations in Georgia cannot be predicted.

CLEAN SMOKESTACKS ACT

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. PEC currently has approximately 5,100 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. In April 2005, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets for NOx and SO_2 from coal-fired plants under the Clean Smokestacks Act of approximately $895 million. We now project that our total capital expenditures to meet these emission targets will be in a range of approximately $1.1 billion to $1.4 billion by the end of 2013, of which approximately $286 million has been spent through December 31, 2005. This increase is primarily due to the higher cost and revised quantities of construction materials, such as concrete and steel, refinement of cost and scope estimates for the current projects, and increases in the estimated inflation factor applied to future project costs. We are evaluating various design, technology, and new generation options that could materially reduce expenditures required by the Clean Smokestacks Act.

Two of the coal-fired generation plants impacted by the Clean Smokestacks Act are jointly owned. The joint owners pay their ownership share of construction costs. In 2005, PEC entered into a contract 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 to approximately $38 million. PEC recognized a $16 million liability in the fourth quarter of 2005, based upon the current estimate for Clean Smokestacks Act compliance. As capital cost projections change, it is reasonably possible that additional losses, which could be material, may be incurred in the future.

The Clean Smokestacks Act also freezes the utilities' base rates for five years, which ends in 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the utilities' last general rate case. The Clean Smokestacks Act requires PEC to amortize $569 million, representing 70 percent of the original cost estimate of $813 million, during the five-year rate freeze period. PEC recognized amortization of $147 million, $174 million and $74 million for the years ended December 31, 2005, 2004 and 2003, respectively, and has recognized $395 million in cumulative amortization through December 31, 2005. The remaining amortization requirement of $174 million will be recorded over the two-year period ending December 31, 2007. The Clean Smokestacks Act permits PEC the flexibility to vary the amortization schedule for recording of the compliance costs from none up to $174 million per year. The NCUC will hold a hearing prior to December 31, 2007, to determine cost recovery amounts for 2008 and future periods.

Pursuant to the Clean Smokestacks Act, PEC entered into an agreement with the state of North Carolina to transfer to the state certain NOx and SO_2 emissions allowances that result from compliance with the collective NOx and SO_2 emissions limitations set out in the Clean Smokestacks Act. The Clean Smokestacks Act also required the state to undertake a study of mercury and CO_2 emissions in North Carolina. O&M expenses will significantly increase due to the additional personnel, materials and general maintenance associated with the equipment. O&M expenses are recoverable through base rates, rather than as part of this program. The future regulatory interpretation, implementation or impact of the Clean Smokestacks Act cannot be predicted.

CLEAN AIR INTERSTATE RULE (CAIR) AND MERCURY RULE

On March 10, 2005, the EPA issued the final CAIR. The EPA's rule requires 28 states, including North Carolina, South Carolina, Georgia and Florida, and the District of Columbia to reduce NOx and SO_2 emissions in order to reduce levels of fine particulate matter and impacts to visibility. The CAIR sets emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2.

PEF has joined a coalition of Florida utilities that has filed a challenge to the CAIR as it applies to Florida. A petition for reconsideration and stay and a petition for judicial review of the CAIR were filed on July 11, 2005. On October 27, 2005, the DC Circuit Court issued an order granting the motion for stay of the proceedings. On December 2, 2005, the EPA announced a reconsideration of four aspects of the CAIR, including its applicability to Florida. While we consider it unlikely that this challenge would eliminate the compliance requirements of the CAIR, it could potentially reduce or delay our costs to comply with the CAIR. The outcome of this matter cannot be predicted.

On March 15, 2005, the EPA finalized two separate but related rules: the Clean Air Mercury Rule (CAMR) that sets emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encourages a cap and trade approach to achieving those caps, and a de-listing rule that eliminated any requirement to pursue a maximum achievable control technology (MACT) approach for limiting mercury emissions from coal-fired power plants. NOx and SO_2 controls also are effective in reducing mercury emissions. However, according to the EPA the second phase cap reflects a level of mercury emissions reduction that exceeds the level that would be achieved solely as a co-benefit of controlling NOx and SO_2 under CAIR.

The de-listing rule has been challenged by a number of parties; the resolution of the challenges could impact our final compliance plans and costs. On October 21, 2005, the EPA announced a reconsideration of the CAMR. The outcome of this matter cannot be predicted.

In conjunction with the proposed mercury rule, the EPA proposed a MACT standard to regulate nickel emissions from residual oil-fired units. The EPA withdrew the proposed nickel rule in March 2005.

We are in the process of determining compliance plans and the cost to comply with the CAIR and CAMR. Installation of additional air quality controls is likely to be needed to meet the CAIR and the CAMR requirements. Compliance costs at PEF are eligible for consideration for recovery through the ECRC. The outcome of future petitions for recovery through the ECRC cannot be predicted.

The air quality controls needed to meet compliance with the NOx SIP Call and Clean Smokestacks Act will reduce the costs to meet the CAIR requirements for our North Carolina units at PEC. We currently estimate the total additional compliance costs related to CAIR for PEC could be in a range of approximately \$100 million to \$200 million. We will continue to review these estimates as compliance plans are further developed. The timing and extent of the costs for future projects will depend upon the final compliance strategy.

We expect PEF to incur significant additional capital and O&M expenses to achieve compliance with the CAIR and CAMR through 2018. We currently estimate the total compliance costs for PEF could be as much as approximately \$1.4 billion, of which approximately \$2 million has been incurred through December 31, 2005. We will continue to review these estimates as compliance plans are further developed. The timing and extent of the costs for future projects will depend upon the final compliance strategy. We are evaluating various design, technology, and new generation options that could materially reduce PEF's costs required by the CAIR and CAMR.

On October 14, 2005, the FPSC approved PEF's petition for the recovery of costs associated with the development and implementation of an integrated strategy to comply with the CAIR and CAMR through the ECRC. PEF is developing an integrated compliance strategy for the CAIR and CAMR rules because NOx and SO_2 controls are effective in reducing mercury emissions. Program costs for 2005 were approximately \$2 million for preliminary engineering activities and strategy development work necessary to determine our integrated compliance strategy. PEF currently projects to spend approximately \$53 million in capital costs to comply with the CAIR and CAMR programs in 2006. These costs may increase or decrease depending upon the results of the engineering and strategy development work. Among other things; subsequent rule interpretations, equipment availability, or the unexpected acceleration of the initial NOx or other compliance dates could require acceleration of some projects and therefore result in additional costs in 2006.

CLEAN AIR VISIBILITY RULE

On June 15, 2005, the EPA issued the final Clean Air Visibility Rule (CAVR). The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas. To help restore visibility in those areas, states must require the identified facilities to install Best Available Retrofit Technology (BART) to control their emissions. Depending on the approach taken by the states, the reductions associated with BART would begin to take effect in 2014. CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of CAIR may be used by states as a BART substitute. We expect that our compliance plans to comply with the CAIR and CAMR will fulfill BART obligations, but the states could require the installation of additional air quality controls if they do not achieve reasonable progress on improving visibility. PEC's BART-eligible units are Asheville Unit No. 1 and No. 2, Roxboro Unit No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF's BART-eligible units are Anclote Unit No. 1, Bartow Unit No. 3, and Crystal River Unit No. 1 and No. 2. The outcome of this matter cannot be predicted.

NORTH CAROLINA ATTORNEY GENERAL PETITION UNDER SECTION 126 OF THE CLEAN AIR ACT

In March 2004, the North Carolina Attorney General filed a petition with the EPA, under Section 126 of the Clean Air Act, asking the federal government to force coal-fired power plants in 13 other states, including South Carolina, to reduce their NOx and SO_2

emissions. The state of North Carolina contends these out-of-state emissions interfere with North Carolina's ability to meet national air quality standards for ozone and particulate matter. On August 1, 2005, the EPA issued a proposed response denying the petition. The EPA's rationale for denial is that compliance with CAIR will reduce the emissions from surrounding states sufficiently to address North Carolina's concerns. The EPA must take final action by March 15, 2006. The outcome of this matter cannot be predicted.

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

On December 21, 2005, the EPA announced proposed changes to the NAAQS for particulate matter. The EPA proposed to lower the 24-hour standard for particulate matter less than 2.5 microns in diameter from 65 micrograms per cubic meter to 35 micrograms per cubic meter. In addition, the EPA proposed to establish a new 24-hour standard of 70 micrograms per cubic meter for particulate matter that is between 2.5 and 10 microns in diameter. The EPA also proposed to eliminate the current standards for particulate matter less than 10 microns in diameter. The EPA is scheduled to finalize the standards by September 27, 2006. The changes could ultimately result in increased costs for installation of additional pollution controls at facilities operated by PEC and PEF. The outcome of this matter cannot be predicted.

C. Water Quality

As a result of the operation of certain control equipment needed to address the air quality issues outlined above, new wastewater streams may be generated at the affected facilities. Integration of these new wastewater streams into the existing wastewater treatment processes may result in permitting, construction and treatment requirements imposed on the Utilities in the immediate and extended future.

Section 316(b) of the Clean Water Act requires assessment of the environmental effect of withdrawal of water at our facilities. We are conducting studies and currently estimate that total compliance costs through 2010 to meet Section 316(b) requirements of the Clean Water Act will be approximately $70 million to $95 million, of which an immaterial amount has been incurred through December 31, 2005. The range includes approximately $5 million to $10 million at PEC and approximately $65 million to $85 million at PEF.

The majority of compliance costs associated with water quality requirements for PEF are eligible for consideration for recovery through the ECRC. The outcome of future petitions for recovery through the ECRC cannot be predicted.

D. Other Environmental Matters

GLOBAL CLIMATE CHANGE

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other greenhouse gases. The treaty went into effect on February 16, 2005. The United States has not adopted the Kyoto Protocol, and the Bush administration has stated it favors voluntary programs. There are proposals to address global climate change that would regulate CO_2 and other greenhouse gases. Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol and some additional proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from customers. We have articulated principles that we believe should be incorporated into any global climate change policy. While the outcome of this matter cannot be predicted, we are taking voluntary action on this important issue as part of our commitment to environmental stewardship and responsible corporate citizenship.

In a decision issued July 15, 2005, a three-judge panel of the U.S. Court of Appeals for the District of Columbia Circuit denied petitions for review filed by several states, cities and organizations seeking the regulation by the EPA of CO_2 emissions under the Clean Air Act. In a 2-1 decision, the court held that the EPA administrator properly exercised his discretion in denying the request for regulation. Officials from five states and the District of Columbia asked the full U.S. Court of Appeals for the D.C. Circuit to review the decision made by the three-judge panel. On December 2, 2005, the U.S. Court of Appeals denied the request for rehearing. On March 2, 2006, the petitioners filed a petition for writ of certiorari with the U.S. Supreme Court, seeking a review of the U.S. Court of Appeals decision. The outcome of this matter cannot be predicted.

In 2005, we initiated a study to assess the impact of constraints on CO_2 and other air emissions. We plan to issue this report by March 31, 2006. While we participate in the development of a national climate change policy framework, we will continue to actively engage others in our region to develop consensus-based solutions, as we did with the Clean Smokestacks Act.

23. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2005, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2006	2007	2008	2009	2010	Thereafter
Fuel	$ 2,786	$ 2,287	$ 1,031	$ 695	$ 268	$ 1,165
Purchased power	471	477	448	414	364	4,308
Construction obligations	74	28	–	–	–	–
Other purchase obligations	89	90	76	64	41	232
Total	$ 3,420	$ 2,882	$ 1,555	$ 1,173	$ 673	$ 5,705

PEC

(in millions)	2006	2007	2008	2009	2010	Thereafter
Fuel	$ 881	$ 849	$ 443	$ 304	$ 151	$ 593
Purchased power	124	122	85	86	43	508
Other Purchase Obligations	14	21	20	–	–	–
Total	$ 1,019	$ 992	$ 548	$ 390	$ 194	$ 1,101

PEF

(in millions)	2006	2007	2008	2009	2010	Thereafter
Fuel	$ 545	$ 544	$ 343	$ 265	$ 104	$ 572
Purchased power	343	355	363	328	321	3,800
Construction obligations	74	28	–	–	–	–
Other purchase obligations	34	36	32	43	19	74
Total	$ 996	$ 963	$ 738	$ 636	$ 444	$ 4,446

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 $3.070 billion, $2.033 billion and $1.645 billion for 2005, 2004 and 2003, respectively. PEC's total payments under these commitments for its generating plants were $964 million, $477 million and $562 million in 2005, 2004 and 2003, respectively. PEF's payments totaled $505 million, $375 million and $209 million in 2005, 2004 and 2003, respectively.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (qualifying facilities or QFs) with expiration dates ranging from 2006 to 2025. These purchased power contracts generally provide for capacity and energy payments.

Pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between PEC and Power Agency, PEC is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, Harris. In 1993, PEC and Power Agency entered into an agreement to restructure portions of their contracts covering power supplies and interests in jointly owned units. Under the terms of the 1993 agreement, PEC increased the amount of capacity and energy purchased from Power Agency's ownership interest in Harris, and the buyback period was extended six years through 2007. The estimated minimum annual payments for these purchases, which reflect capacity and energy costs, total approximately $34 million. These contractual purchases totaled $37 million, $39 million and $36 million for 2005, 2004 and 2003, respectively.

PEC has a long-term agreement for the purchase of power and related transmission services from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The agreement provides for the purchase of 250 MW of capacity through 2009 with estimated minimum annual payments of approximately $44 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $71 million, $62 million and $66 million for 2005, 2004 and 2003, respectively.

PEC executed two long-term agreements for the purchase of power from Broad River LLC's Broad River facility (Broad River). One agreement provides for the purchase of approximately 500 MW of capacity through 2021 with an original minimum annual payment of approximately $16 million, primarily representing capital-related capacity costs. The second agreement provided for the additional purchase of approximately 335 MW of capacity through 2022 with an original minimum annual payment of approximately $16 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River agreements amounted to $44 million, $42 million and $37 million in 2005, 2004 and 2003, respectively.

PEC has various pay-for-performance contracts with QFs for approximately 354 MW of capacity expiring at various times through 2014. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $112 million in 2005, $90 million in 2004 and $113 million in 2003.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2015. Total purchases, for both energy and capacity, under these agreements amounted to $175 million, $128 million and $126 million for 2005, 2004 and 2003, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $64 million annually through 2009, $54 million for 2010 and $38 million annually thereafter through 2015.

PEF has ongoing purchased power contracts with certain QFs for 812 MW of capacity with expiration dates ranging from 2006 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the qualifying facilities meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the generating capacity of each of the facilities. All commitments have been approved by the FPSC. Total capacity purchases under these contracts amounted to $262 million, $247 million and $244 million for 2005, 2004 and 2003, respectively. At December 31, 2005, minimum expected future capacity payments under these contracts were $279 million, $289 million, $297 million, $262 million and $267 million for 2006 through 2010, respectively, and $3.6 billion thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost recovery clause.

On December 2, 2004, PEF entered into precedent and related agreements with Southern Natural Gas Company (SNG), Florida Gas Transmission Company (FGT), and BG LNG Services, LLC for the supply of natural gas and associated firm pipeline transportation to augment PEF's gas supply needs for the period from May 1, 2007, to April 30, 2027. The total cost to PEF associated with the agreements is approximately $4.0 billion. The transactions are subject to several conditions precedent, some of which have been satisfied, which include obtaining the FPSC's approval of the agreements, the completion and commencement of operation of the necessary related expansions to SNG's and FGT's respective natural gas pipeline systems, and other standard closing conditions. Due to the conditions in the agreements, the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

In January 2006, PEF entered into a conditional contract with Gulfstream Gas System, L.L.C. (Gulfstream) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from September 1, 2008 through December 31, 2031. The total cost to PEF associated with this agreement is approximately $1.0 billion. The transaction is subject to several conditions precedent, including the completion and commencement of operation of the necessary related expansions to Gulfstream's natural gas pipeline system, and other standard closing conditions. Due to the timing of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $91 million, $108 million and $158 million for 2005, 2004 and 2003, respectively. At December 31, 2005, PEC has no construction obligations. Total purchases by PEC under various combustion turbine construction obligations were $5 million and $21 million for 2004 and 2003, respectively. PEC did not have any purchases related to construction obligations in 2005. PEF has purchase obligations related to various plant capital projects at the Hines Energy Complex. Total payments under PEF's contracts were $91 million, $102 million and $137 million for 2005, 2004 and 2003, respectively. PEF's future obligations under these contracts are $74 million for 2006 and $28 million for 2007.

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and a PEF service agreement related to the Hines Energy Complex. Our payments under these agreements were $97 million, $58 million and $31 million for 2005, 2004 and 2003, respectively.

On December 31, 2002, PEC and PVI entered into a contractual commitment to purchase at least $11 million and $4 million, respectively, of capital parts by December 31, 2010. During 2005, 2004 and 2003, no capital parts have been purchased under this contract.

PEC has various purchase obligations related to reactor vessel head replacements, power uprates and spent fuel storage. Total purchases under these contracts were $13 million for 2005, $17 million for 2004 and $3 million for 2003. Future purchase obligations are $7 million for 2006.

PEF has long-term service agreements for the Hines Energy Complex. Total payments under these contracts were $8 million, $11 million and $3 million for 2005, 2004 and 2003, respectively. Future obligations under these contracts are $14 million, $11 million, $16 million, $14 million and $19 million for 2006 through 2010, respectively, with approximately $74 million payable thereafter.

PEF has various purchase obligations and contractual commitments related to the purchase and replacement of machinery. Total payments under these contracts were $34 million for 2005. Future obligations under these contracts are $20 million and $25 million in 2006 and 2007, respectively, and $6 million in 2008 and 2009.

PVI has purchase obligations with two counterparties for pipeline capacity through 2018 and 2028. Payments under these agreements were $15 million, $13 million and $6 million for 2005, 2004 and 2003, respectively. Future obligations under these contracts are approximately $16 million for 2006 through 2010 and approximately $117 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 $48 million, $57 million and $54 million for 2005, 2004 and 2003, respectively. Our purchased power expense under agreements classified as operating leases were approximately $14 million in 2005, $25 million in 2004 and $5 million in 2003.

PEC's rent expense under operating leases totaled $24 million for 2005 and $20 million for 2004 and 2003. These amounts include rent expense allocated from PESC of $7 million for 2005 and $10 million for 2004 and 2003. Purchased power expense under agreements classified as operating leases were approximately $11 million during 2005, $25 million during 2004 and $5 million during 2003.

PEF's rent expense under operating leases totaled $11 million, $14 million and $17 million during 2005, 2004 and 2003, respectively. These amounts include rent expense allocated from PESC to PEF of $7 million for 2005 and $10 million for 2004 and 2003. Purchased power expense under agreements classified as operating leases was approximately $3 million during 2005.

Assets recorded under capital leases at December 31 consisted of:

	Progress Energy		PEC	
(in millions)	**2005**	2004	**2005**	2004
Buildings	**$ 30**	$ 30	$ 30	$ 30
Equipment and other	**27**	2	–	–
Less: Accumulated amortization	**(12)**	(11)	(12)	(11)
Total	**$ 45**	$ 21	$ 18	$ 19

At December 31, 2005, 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
2006	$ 4	$ 76	$ 2	$ 36	$ –	$ 25
2007	4	88	2	31	–	45
2008	4	88	3	31	–	48
2009	4	85	2	30	–	47
2010	4	71	3	18	–	47
Thereafter	21	298	14	158	–	102
	41	$ 706	26	$ 304	–	$ 314
Less amount representing imputed interest	(12)		(7)		–	
Present value of net minimum lease payments under capital leases	$ 29		$ 19		$ –	

In 2003, we entered into a new operating lease for a building, for which minimum annual rental payments are included in the table above. The lease terms provide for no rental payments during the last 15 years of the lease, during which period $53 million of rental expense will be recorded in the Consolidated Statements of Income.

In 2005, PEF entered into an agreement for a new capital lease beginning in 2007 for a building that is currently under construction. The lease calls for annual payments of approximately $6 million from 2007 through 2026 for a total of approximately $110 million. The lease term provides for no payments during the last 20 years of the lease.

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 for 2006 through 2010 are approximately $40 million, $24 million, $17 million, $13 million and $4 million, respectively, with $24 million receivable thereafter. Rents received under these operating leases totaled $66 million, $60 million and $45 million for 2005, 2004 and 2003, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals under noncancelable leases are $10 million for 2006 and none thereafter. Rents received are contingent upon usage and totaled $31 million, $32 million and $31 million for 2005, 2004 and 2003, respectively.

PEF's rents received are based on a fixed minimum rental where price varies by type of equipment and totaled $63 million for 2005 and 2004 and $56 million for 2003. Minimum rentals receivable (excluding streetlights) under noncancelable leases for 2006 is $5 million and none thereafter. Streetlight rentals were $42 million, $40 million and $38 million for 2005, 2004 and 2003, respectively. Future streetlight rentals would approximate 2005 revenues.

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 No. 45). These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes (See Note 19). Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit, surety bonds and guarantees in support of nuclear decommissioning. At December 31, 2005, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Balance Sheets.

At December 31, 2005, we have issued guarantees and indemnifications of certain legal, tax and environmental matters to third parties in connection with sales of businesses and for timely payment of obligations in support of our nonwholly owned synthetic fuel operations. Related to the sales of businesses, the notice period extends until 2012 for the majority of matters provided for in the indemnification provisions. For matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain environmental indemnifications have no limitations as to time or maximum potential future payments. Other guarantees and indemnifications have an estimated maximum exposure of approximately $152 million. Additionally, in 2005 PEC entered into a contract 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 $16 million liability related to this indemnification (See Note 22B). At December 31, 2005, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $41 million. 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 24).

D. Other Commitments and Contingencies

1. Spent Nuclear Fuel Matters

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

The DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, the Utilities filed a complaint in the United States Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from our various facilities on or before January 31, 1998. Our damages due to the DOE's breach will be significant, but have yet to be determined. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims.

The DOE and the Utilities have agreed to a stay of the lawsuit, including discovery. The parties agreed to, and the trial court entered, a stay of proceedings, in order to allow for possible efficiencies due to the resolution of legal and factual issues in previously filed cases in which similar claims are being pursued by other plaintiffs. These issues may include, among others, so-called "rate issues," or the minimum mandatory schedule for the acceptance of spent nuclear fuel and high-level waste by which the government was contractually obligated to accept contract holders' spent nuclear fuel and/or high-level waste, and issues regarding recovery of damages under a partial breach of contract theory that will be alleged to occur in the future. These issues have been or are expected to be presented in the trials or appeals that are currently scheduled to occur during 2006. Resolution of these issues in other cases could facilitate agreements by the parties in the Utilities' lawsuit, or at a minimum, inform the court of decisions reached by other courts if they remain contested and require resolution in this case. In July 2005, the parties jointly requested a continuance of the stay through December 15, 2005, which the trial court granted. Subsequently, the trial court continued the stay until March 17, 2006.

In July 2002, Congress passed an override resolution to Nevada's veto of the DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nev. In January 2003, the state of Nevada; Clark County, Nev.; and Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged the EPA's radiation standards for Yucca Mountain. On July 9, 2004, the Court rejected the challenge to the constitutionality of the resolution approving Yucca Mountain, but ruled that the EPA was wrong to set a 10,000-year compliance period in the radiation protection standard. In August 2005, the EPA issued new proposed standards. The proposed standards include a 1,000,000-year compliance period in the radiation protection standard. Comments were due November 21, 2005, and are being reviewed by the EPA. The EPA has not scheduled a date for issuance of revised proposed standards. The DOE originally planned to submit a license application to the NRC to construct the Yucca Mountain facility by the end of 2004. However, in November 2004, the DOE announced it would not submit the license application until mid-2005 or later. The DOE did not submit the license application in 2005 and has not provided a new target date for submission of the license application. Congress approved $450 million for fiscal year 2006 for the Yucca Mountain project, approximately $201 million less than requested by the DOE. The DOE has acknowledged that a working repository will not be operational until sometime after 2010, but the DOE has not identified a new target date. The Utilities cannot predict the outcome of this matter.

On February 27, 2004, PEC requested to have its license for the Independent Spent Fuel Storage Installation at Robinson extended by 20 years with an exemption request for an additional 20-year extension. Its current license expires in August 2006 and on March 30, 2005, the NRC issued a 40-year license renewal.

With certain modifications and additional approval by the NRC, including the installation of onsite dry storage facilities at Robinson and Brunswick, PEC's spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on PEC's system through the expiration of the operating licenses for all of PEC's nuclear generating units.

With certain modifications and additional approval by the NRC, including the installation of onsite dry storage facilities at PEF's nuclear unit, CR3, PEF's spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on PEF's system through the expiration of the operating license for CR3.

2. Synthetic Fuel Matters

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity that own facilities that produce coal-based solid synthetic fuel as defined under Section 29 of the Code (Section 29). The production and sale of the synthetic fuel from these facilities qualify for tax credits under Section 29/45K if certain requirements are satisfied, including a requirement that the synthetic fuel differs significantly in chemical composition from the coal used to produce such synthetic fuel and that the fuel was produced from a facility that was placed in service before July 1, 1998. Qualifying synthetic fuel facilities entitle their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuel produced and sold by these plants.

On August 8, 2005, the Energy Policy Act of 2005 (EPACT) was signed into law. This new federal law contains key provisions affecting the electric power industry, including the redesignation of the Section 29 tax credit as a general business credit under Section 45K of the Code (Section 45K). The previous amount of Section 29 tax credits that we were allowed to claim in any calendar year through December 31, 2005, was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized are currently carried forward indefinitely as deferred alternative minimum tax credits. The redesignation of Section 29 tax credits as a Section 45K general business credit was effective on January 1, 2006, and removes the regular federal income tax liability limit on synthetic fuel production and subjects the credits to a 20-year carry forward period. This provision would allow us to produce synthetic fuel to a higher level than we have historically produced should we choose to do so.

Total Section 29 credits generated through December 31, 2005 (including those generated by Florida Progress prior to our acquisition), are approximately $1.7 billion, of which $819 million has been used to offset regular federal income tax liability and $922 million is being carried forward as deferred alternative minimum tax credits. The current synthetic fuel tax credit program expires at the end of 2007.

IRS PROCEEDINGS

In July 2004, we were notified that the IRS field auditors anticipated taking an adverse position regarding the placed-in-service date of the Earthco facilities. On October 29, 2004, we received the IRS field auditors' preliminary report concluding that the Earthco facilities had not been placed in service before July 1, 1998, and proposing that the tax credits generated by those facilities be disallowed.

During October 2005, we and the IRS field auditors filed briefs with the National Office for the purpose of receiving technical advice on whether our Earthco facilities were placed in service prior to July 1, 1998, in order to determine if our synthetic fuel tax credits are allowable under Section 29 of the Internal Revenue Code. During February 2006, the IRS field auditors verbally informed us that the IRS National Office concluded that our four Earthco synthetic fuel facilities met the placed-in-service requirement. The IRS field auditors also indicated that, once they receive written confirmation of the National Office's conclusion, the IRS field auditors will close their audit without any disallowance of tax credits. On February 28, 2006, we received our copy of the National Office Technical Advice Memorandum that concludes that the Earthco facilities met the placed-in-service requirement.

PERMANENT SUBCOMMITTEE

In October 2003, the United States Senate Permanent Subcommittee on Investigations began a general investigation concerning synthetic fuel tax credits claimed under Section 29. The investigation is examining the utilization of the credits, the nature of the technologies and fuels created, the use of the synthetic fuel and other aspects of Section 29 and is not specific to our synthetic fuel operations. Progress Energy provided information in connection with this investigation. We cannot predict the outcome of this matter.

IMPACT OF CRUDE OIL PRICES

Although the Section 29/45K tax credit program is expected to continue through 2007, recent market conditions, world events and catastrophic weather events have increased the volatility and level of oil prices that could limit the amount of those credits or eliminate them entirely for the years following 2005. This possibility is due to a provision of Section 29 that provides that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeds a certain threshold price (the Threshold Price), the amount of Section 29/45K tax credits is reduced for that year. Also, if the Annual Average Price increases high enough (the Phase-out Price), the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation. Synthetic fuel is not economical to produce absent the associated tax credits.

If the Annual Average Price falls between the Threshold Price and the Phase-out Price for a year, the amount by which Section 29/45K tax credits are reduced will depend on where the Annual Average Price falls in that continuum. For example, for 2004, the Threshold Price was $51.35 per barrel and the Phase-out Price was $64.47 per barrel. If the Annual Average Price had been $57.91 per barrel, there would have been a 50 percent reduction in the amount of Section 29 tax credits for that year.

The secretary of the Treasury calculates the Annual Average Price based on the Domestic Crude Oil First Purchases Prices published by the Energy Information Agency (EIA). Because the EIA publishes its information on a three-month lag, the secretary of the Treasury finalizes the calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2005 is expected to be published in early April 2006.

We estimate that the 2005 Threshold Price will be approximately $52 per barrel and the Phase-out Price will be approximately $65 per barrel, based on an estimated 2005 inflation adjustment. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $5 lower than the corresponding monthly New York Mercantile Exchange (NYMEX) settlement price for light sweet crude oil. Through December 31, 2005, the average NYMEX contract settlement price for light sweet crude oil was $55 per barrel. Assuming that the $5 average differential between the Domestic Crude Oil First Purchases Price published by the EIA and the NYMEX settlement price continued through December 31, 2005, we do not currently believe that the 2005 Annual Average Price will cause a phase-out of the synthetic fuel tax credits in 2005.

We estimate that the 2006 Threshold Price will be approximately $52 per barrel and the Phase-out Price will be approximately $66 per barrel, based on estimated inflation adjustments for 2005 and 2006. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $5 lower than the corresponding monthly NYMEX settlement price for light sweet crude oil. As of January 31, 2006, the average NYMEX futures price for light sweet crude oil for calendar year 2006 was $69 per barrel. Based upon the estimated 2006 Threshold Price and Phase-out Price, if oil prices for 2006 remained at the January 31, 2006, average futures price level of $69 per barrel for the entire year in 2006, we currently estimate that the synthetic fuel tax credit amount for 2006 would be reduced by approximately 75 percent to 85 percent. Therefore, the estimated value of 2006 tax credits of approximately $27 per ton would be reduced to approximately $4 to $7 per ton for any synthetic fuel produced in 2006.

In November 2005, the U.S. Senate passed Senate Bill 2020, The Tax Relief Act of 2005, which includes proposed modifications to the Section 29/45K synthetic fuel tax credit program. This legislation would provide synthetic fuel producers with additional certainty around future synthetic fuel production decisions. The proposed modifications include amendments of the phase-out calculation and the annual inflation adjustment for the value of the synthetic fuel tax credits. Under Senate Bill 2020, the Annual Average Price, Threshold Price and the Phase-out Price for 2006 and 2007 would be based on the calculated amounts for the previous calendar year. In addition, the annual inflation adjustment for the synthetic fuel tax credits for 2005, 2006 and 2007 would be eliminated. The U.S. House version of the Tax Reconciliation bill does not include these same provisions. The differences in the Senate and House versions of the bill will be reconciled in conference. We cannot predict with any certainty the likelihood of this legislation passing.

As noted above, we do not currently believe that the 2005 Annual Average Price will cause a phase-out of the synthetic fuel tax credits related to synthetic fuel production in 2005. Therefore, if the provisions of Senate Bill 2020 regarding changes to the Section 29/45K synthetic fuel tax credit program were enacted into law, there would be no phase-out of these tax credits in calendar year 2006. However, we cannot predict with any certainty the price of oil for 2006 or 2007 and, therefore, we cannot predict what impact, if any, this proposed legislation would have on the value of tax credits in 2007.

Our future synthetic fuel production levels for 2006 and 2007 remain uncertain because we cannot predict with any certainty the Annual Average Price of oil for 2006 or 2007 or the likelihood of legislation modifying the phase-out calculation being enacted into law. If oil prices for 2006 remained at the January 31, 2006, average futures price level of $69 per barrel for the entire year in 2006, it is unlikely that we would produce significant amounts of synthetic fuel in 2006 and could potentially forfeit credits associated with any 2006 synthetic fuel production. This could have a material adverse impact on our results of operations. We will continue to monitor the level of oil prices and retain the ability to adjust production based on future oil price levels.

Due to the significant uncertainty surrounding our synthetic fuel production in 2006 and 2007 based on the current level of oil prices, we evaluated our synthetic fuel and other related operating long-lived assets for impairment during the third quarter and fourth quarter of 2005. We determined that no impairment of these assets was required. However, an increase in oil prices or a decrease in future synthetic fuel production and cash flows could require additional impairment evaluations in the future, which could result in a future impairment of these assets, which have total carrying values as of December 31, 2005, of approximately $111 million. The majority of these assets will be fully depreciated by the end of 2007, the scheduled end of the synthetic fuel tax credit program. The outcome of this matter cannot be determined.

SALE OF PARTNERSHIP INTEREST

In June 2004, through our subsidiary Progress Fuels, we sold in two transactions a combined 49.8 percent partnership interest in Colona, one of our synthetic fuel facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gains from the sales will be recognized on a cost recovery basis as the facility produces and sells synthetic fuel and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectability is reasonably assured. Gain recognition is dependent on the synthetic fuel production qualifying for Section 29 tax credits and the value of such tax credits as discussed above. Until the gain recognition criteria are met, gains from selling interests in Colona will be deferred. It is possible that gains will be deferred in the first, second and/or third quarters of each year until there is persuasive evidence that no tax credit phase-out will occur for the applicable calendar year. This could result in shifting earnings from earlier quarters to later quarters in a calendar year. In the event that the synthetic fuel tax credits from the Colona facility are reduced, including an increase in the price of oil that could limit or eliminate synthetic fuel tax credits, the amount of proceeds realized from the sale could be significantly impacted. We recognized a pre-tax gain on monetization of $30 million during 2005 based on the remote possibility of any phase-out of the synthetic fuel tax credits in 2005. A portion of this gain had been deferred through the third quarter of 2005.

CONTINGENT ROYALTY PAYMENTS

We have certain future commitments related to four synthetic fuel facilities purchased that provide for contingent payments (royalties). The related agreements and their amendments require the payment of minimum annual royalties of approximately $7 million for each plant through 2007. We recorded a liability (included in other liabilities and deferred credits on the Consolidated Balance Sheets) and a deferred asset (included in other assets and deferred debits in the Consolidated Balance Sheets), each of approximately $50 million and $73 million at December 31, 2005 and 2004, respectively, representing the minimum amounts due through 2007, discounted at 6.05%. At December 31, 2005 and 2004, the portions of the asset and liability recorded that were classified as current were approximately $26 million. The deferred asset will be amortized to expense each year as synthetic fuel sales are made. The maximum amounts payable under these agreements remain unchanged. Future expected annual minimum royalty payments are approximately $26 million for 2006 and 2007. We have exercised our right under the related agreements to escrow those payments if certain conditions in the agreements were met, as more fully described below.

On May 15, 2005, the original owners of the Earthco synthetic fuel facilities filed suit in New York state court alleging breach of contract against the Progress Fuels subsidiaries that purchased the Earthco facilities (Progress Fuels Subsidiaries). The plaintiffs also named us as a defendant. The plaintiffs allege that periodic payments due to them under the sales arrangement with the Progress Fuels Subsidiaries are being improperly withheld and escrowed. The Progress Fuels Subsidiaries believe that the parties' agreements allow for the payments to be escrowed in the event of an audit, investigation or other proceeding under which the IRS can disallow the tax credits associated with the Earthco facilities. They also believe that the agreements allow for the use of such escrowed amounts to satisfy any potential disallowance of tax credits that arises out of such an event. Currently, the escrowed amount in question is $97 million, which reflects periodic payments that would have been paid to the plaintiffs beginning April 30, 2003, through January 31, 2006. This amount will increase as future periodic payments are made to the escrow, which would otherwise have been payable to the plaintiffs. Plaintiffs filed a partial summary judgment motion in December 2005 seeking payment of the escrowed money. The Progress Fuels Subsidiaries oppose the motion and will file opposition papers, which are not yet due. The parties are now engaged in discovery.

In addition, 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 (collectively the Earthco Sellers), EFC Synfuel LLC (which is owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC, Solid Fuel LLC, Ceredo Synfuel LLC, Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively the Progress Affiliates), as amended by an amendment to Purchase Agreement as of August 23, 2000 (the Asset Purchase Agreement). Global has asserted that pursuant to the Asset Purchase Agreement it is entitled to an interest in two synthetic fuel facilities currently owned by the Progress Affiliates, and an option to purchase additional interests in the two synthetic fuel facilities.

The first suit, U.S. Global LLC v. Progress Energy, Inc. et al., was filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case). The Florida Global Case asserts claims for breach of the Asset Purchase Agreement and other contract and tort claims related to the Progress Affiliates' alleged interference with Global's rights under the Asset Purchase Agreement. The Florida Global Case requests an unspecified amount of compensatory damages, as well as declaratory relief. Following briefing and argument on a number of dispositive motions on successive versions of Global's complaint, on August 16, 2004, the Progress Affiliates answered the Fourth Amended Complaint by generally denying all of Global's substantive allegations and asserting numerous affirmative defenses. The parties are currently engaged in discovery in the Florida Global Case.

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

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss and entered an order staying 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.

The Progress Affiliates believe that the parties' agreements allow for the payments due to Global to be escrowed in the event of an audit, investigation or other proceeding under which the IRS can disallow the tax credits and also allow for the use of such escrowed amounts to satisfy any potential disallowance of tax credits that arises out of such an event. Currently, the escrowed amount in question is $37 million, which reflects periodic payments that would have been paid to the plaintiffs beginning April 30, 2003, through January 31, 2006. This amount will increase as future periodic payments are made to the escrow that would otherwise have been payable to the plaintiffs.

We cannot predict the outcome of these matters, but will vigorously defend against the allegations.

3. Franchise Matters

PEF has largely resolved its outstanding franchise matters. In August 2005, the cities of Edgewood, Fla. (1,400 customers), and Maitland, Fla. (7,000 customers), approved new 30-year electric utility franchise agreements with PEF. In November 2005, the 2,500 customer town of Belleair, Fla., voted to reject a referendum to municipalize, but has not yet signed a new utility franchise agreement with PEF. As previously noted, in accordance with the terms of an arbitration panel's award issued in May 2003 and after satisfying regulatory and operational requirements, Winter Park acquired from PEF the electric distribution system that serves Winter Park (14,000 customers) and PEF transferred the distribution system to Winter Park on June 1, 2005. In addition, Winter Park executed a wholesale power supply contract with PEF with a five-year term and a renewal option (See Note 7C).

4. Other Litigation Matters

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

24. CONDENSED CONSOLIDATING STATEMENTS

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

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

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

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. As of December 31, 2005, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a special-purpose entity and in accordance with the provisions of FIN No. 46R, we deconsolidated the Trust on December 31, 2003. The deconsolidation was not material to our financial statements and resulted in recording an additional equity investment in the Trust of approximately $9 million, an increase in outstanding debt of approximately $8 million and a gain of approximately $1 million relating to the cumulative effect of a change in accounting principle. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In the following tables, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the financial results of Florida Progress. The Other column includes the consolidated financial results of all other nonguarantor subsidiaries and elimination entries for all intercompany transactions. All applicable corporate expenses have been allocated appropriately among the guarantor and nonguarantor subsidiaries.

Condensed Consolidating Statement of Income
Year Ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$ 3,955	$ 3,990	$ 7,945
Diversified business	–	1,496	667	2,163
Total operating revenues	–	5,451	4,657	10,108
Operating expenses				
Utility				
Fuel used in electric generation	–	1,323	1,036	2,359
Purchased power	–	694	354	1,048
Operation and maintenance	12	852	906	1,770
Depreciation and amortization	–	334	588	922
Taxes other than on income	4	279	177	460
Other	–	(26)	(11)	(37)
Diversified business				
Cost of sales	–	1,338	737	2,075
Depreciation and amortization	–	79	73	152
Other	–	41	33	74
Total operating expenses	16	4,914	3,893	8,823
Equity in earnings of consolidated subsidiaries	884	–	(884)	–
Other income (expense), net	66	(4)	(51)	11
Interest charges, net	300	178	162	640
Income (loss) from continuing operations before income tax and minority interest	634	355	(333)	656
Income tax (benefit) expense	(63)	(40)	58	(45)
Minority interest in subsidiaries' loss, net of tax	–	(26)	–	(26)
Income (loss) from continuing operations	697	421	(391)	727
Discontinued operations, net of tax	–	(47)	16	(31)
Cumulative effect of changes in accounting principles, net of tax	–	–	1	1
Net income (loss)	$ 697	$ 374	$ (374)	$ 697

Condensed Consolidating Statement of Income
Year Ended December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$ 3,525	$ 3,628	$ 7,153
Diversified business	–	1,125	247	1,372
Total operating revenues	–	4,650	3,875	8,525
Operating expenses				
Utility				
Fuel used in electric generation	–	1,175	836	2,011
Purchased power	–	567	301	868
Operation and maintenance	10	630	835	1,475
Depreciation and amortization	–	281	597	878
Taxes other than on income	(2)	254	173	425
Other	–	(2)	(11)	(13)
Diversified business				
Cost of sales	–	981	198	1,179
Depreciation and amortization	–	78	79	157
Other	–	17	84	101
Total operating expenses	8	3,981	3,092	7,081
Equity in earnings of consolidated subsidiaries	940	–	(940)	–
Other income (expense), net	65	(4)	(59)	2
Interest charges, net	295	162	171	628
Income (loss) from continuing operations before income tax and minority interest	702	503	(387)	818
Income tax (benefit) expense	(57)	61	102	106
Minority interest in subsidiaries' loss, net of tax	–	(17)	–	(17)
Income (loss) from continuing operations	759	459	(489)	729
Discontinued operations, net of tax	–	15	15	30
Net income (loss)	$ 759	$ 474	$ (474)	$ 759

Condensed Consolidating Statement of Income
Year Ended December 31, 2003

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$ 3,152	$ 3,589	$ 6,741
Diversified business	–	830	228	1,058
Total operating revenues	–	3,982	3,817	7,799
Operating expenses				
Utility				
Fuel used in electric generation	–	870	825	1,695
Purchased power	–	566	296	862
Operation and maintenance	19	640	762	1,421
Depreciation and amortization	–	307	576	883
Taxes other than on income	2	241	162	405
Other	–	–	(8)	(8)
Diversified business				
Cost of sales	–	736	193	929
Depreciation and amortization	–	62	64	126
Other	–	80	62	142
Total operating expenses	21	3,502	2,932	6,455
Equity in earnings of consolidated subsidiaries	1,039	–	(1,039)	–
Other income (expense), net	47	(8)	(76)	(37)
Interest charges, net	319	142	146	607
Income (loss) from continuing operations before income tax and minority interest	746	330	(376)	700
Income tax (benefit) expense	(36)	(112)	35	(113)
Minority interest in subsidiaries' income, net of tax	–	2	–	2
Income (loss) from continuing operations	782	440	(411)	811
Discontinued operations, net of tax	–	7	(12)	(5)
Cumulative effect of changes in accounting principles, net of tax	–	–	(24)	(24)
Net income (loss)	$ 782	$ 447	$ (447)	$ 782

Condensed Consolidating Balance Sheet
December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$ 5,821	$ 8,621	$ 14,442
Current assets				
Cash and cash equivalents	239	241	126	606
Short-term investments	–	–	191	191
Receivables from affiliated companies	713	–	(713)	–
Deferred fuel cost	–	341	261	602
Assets of discontinued operations	–	107	2	109
Other current assets	22	1,069	1,139	2,230
Total current assets	974	1,758	1,006	3,738
Deferred debits and other assets				
Investment in consolidated subsidiaries	11,594	–	(11,594)	–
Goodwill	–	2	3,717	3,719
Other assets and deferred debits	13	2,174	2,937	5,124
Total deferred debits and other assets	11,607	2,176	(4,940)	8,843
Total assets	$ 12,581	$ 9,755	$ 4,687	$ 27,023
Capitalization				
Common stock equity	$ 8,038	$ 3,039	$ (3,039)	$ 8,038
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	38	5	43
Long-term debt, affiliate	–	440	(170)	270
Long-term debt, net	3,873	2,636	3,667	10,176
Total capitalization	11,911	6,187	522	18,620
Current liabilities				
Current portion of long-term debt	404	109	–	513
Notes payable to affiliated companies	–	315	(315)	–
Short-term obligations	–	102	73	175
Liabilities of discontinued operations	–	40	–	40
Other current liabilities	245	855	1,017	2,117
Total current liabilities	649	1,421	775	2,845
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	60	218	278
Regulatory liabilities	–	1,189	1,338	2,527
Accrued pension and other benefits	12	307	551	870
Other liabilities and deferred credits	9	591	1,283	1,883
Total deferred credits and other liabilities	21	2,147	3,390	5,558
Total capitalization and liabilities	$ 12,581	$ 9,755	$ 4,687	$ 27,023

Condensed Consolidating Balance Sheet
December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$ 5,882	$ 8,481	$ 14,363
Current assets				
Cash and cash equivalents	5	24	27	56
Short-term investments	–	–	82	82
Receivables from affiliated companies	1,415	5	(1,420)	–
Deferred fuel cost	–	89	140	229
Assets of discontinued operations	–	696	(11)	685
Other current assets	23	920	1,037	1,980
Total current assets	1,443	1,734	(145)	3,032
Deferred debits and other assets				
Investment in consolidated subsidiaries	11,061	–	(11,061)	–
Goodwill	–	2	3,717	3,719
Other assets and deferred debits	16	2,068	2,846	4,930
Total deferred debits and other assets	11,077	2,070	(4,498)	8,649
Total assets	$ 12,520	$ 9,686	$ 3,838	$ 26,044
Capitalization				
Common stock equity	$ 7,633	$ 2,681	$ (2,681)	$ 7,633
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	32	4	36
Long-term debt, affiliate	–	809	(539)	270
Long-term debt, net	4,449	2,052	2,750	9,251
Total capitalization	12,082	5,608	(407)	17,283
Current liabilities				
Current portion of long-term debt	–	49	300	349
Notes payable to affiliated companies	–	431	(431)	–
Short-term obligations	170	293	221	684
Liabilities of discontinued operations	–	186	–	186
Other current liabilities	245	931	688	1,864
Total current liabilities	415	1,890	778	3,083
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	64	584	648
Regulatory liabilities	–	1,362	1,292	2,654
Accrued pension and other benefits	10	248	375	633
Other liabilities and deferred credits	13	514	1,216	1,743
Total deferred credits and other liabilities	23	2,188	3,467	5,678
Total capitalization and liabilities	$ 12,520	$ 9,686	$ 3,838	$ 26,044

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

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 257	$ 515	$ 702	$ 1,474
Investing activities				
Gross utility property additions	–	(496)	(584)	(1,080)
Diversified business property additions	–	(190)	(16)	(206)
Nuclear fuel additions	–	(47)	(79)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	462	13	475
Purchases of available-for-sale securities and other investments	(1,702)	(405)	(1,878)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	1,702	405	1,738	3,845
Changes in advances to affiliates	702	5	(707)	–
Contributions to consolidated subsidiaries	(13)	–	13	–
Acquisition of intangibles	–	–	(3)	(3)
Other investing activities	1	(26)	(12)	(37)
Net cash provided (used) by investing activities	690	(292)	(1,515)	(1,117)
Financing activities				
Issuance of common stock	208	–	–	208
Proceeds from issuance of long-term debt, net	–	744	898	1,642
Net decrease in short-term indebtedness	(170)	(191)	(148)	(509)
Retirement of long-term debt	(160)	(473)	69	(564)
Dividends paid on common stock	(582)	–	–	(582)
Dividends paid to parent	–	(2)	2	–
Changes in advances from affiliates	–	(101)	101	–
Contributions from parent	–	11	(11)	–
Other financing activities	(9)	40	1	32
Net cash (used) provided by financing activities	(713)	28	912	227
Cash used by discontinued operations				
Operating activities	–	(13)	–	(13)
Investing activities	–	(21)	–	(21)
Financing activities	–	–	–	–
Net increase in cash and cash equivalents	234	217	99	550
Cash and cash equivalents at beginning of year	5	24	27	56
Cash and cash equivalents at end of year	$ 239	$ 241	$ 126	$ 606

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

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 653	$ 571	$ 341	$ 1,565
Investing activities				
Gross utility property additions	–	(482)	(516)	(998)
Diversified business property additions	–	(150)	(19)	(169)
Nuclear fuel additions	–	–	(101)	(101)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	343	30	373
Purchases of available-for-sale securities and other investments	–	(569)	(2,565)	(3,134)
Proceeds from sales of available-for-sale securities and other investments	–	569	2,679	3,248
Changes in advances to affiliates	27	(5)	(22)	–
Contributions to consolidated subsidiaries	(15)	–	15	–
Acquisition of intangibles	–	–	(1)	(1)
Other investing activities	–	(23)	(6)	(29)
Net cash provided (used) by investing activities	12	(317)	(506)	(811)
Financing activities				
Issuance of common stock	73	–	–	73
Proceeds from issuance of long-term debt, net	365	56	–	421
Net increase in short-term indebtedness	170	293	217	680
Retirement of long-term debt	(705)	(68)	(580)	(1,353)
Dividends paid on common stock	(558)	–	–	(558)
Dividends paid to parent	–	(340)	340	–
Changes in advances from affiliates	–	(209)	209	–
Contributions from parent	–	12	(12)	–
Other financing activities	(5)	13	(2)	6
Net cash (used) provided by financing activities	(660)	(243)	172	(731)
Cash provided (used) by discontinued operations				
Operating activities	–	44	–	44
Investing activities	–	(46)	–	(46)
Financing activities	–	–	–	–
Net increase in cash and cash equivalents	5	9	7	21
Cash and cash equivalents at beginning of year	–	15	20	35
Cash and cash equivalents at end of year	$ 5	$ 24	$ 27	$ 56

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2003

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 524	$ 517	$ 547	$ 1,588
Investing activities				
Gross utility property additions	–	(526)	(446)	(972)
Diversified business property additions	–	(302)	(146)	(448)
Nuclear fuel additions	–	(51)	(66)	(117)
Proceeds from sales of discontinued operations and other assets, net of cash divested	451	100	28	579
Purchases of available-for-sale securities and other investments	–	(441)	(3,351)	(3,792)
Proceeds from sales of available-for-sale securities and other investments	–	441	3,088	3,529
Changes in advances to affiliates	(327)	(16)	343	–
Contributions to consolidated subsidiaries	(411)	–	411	–
Acquisition of intangibles	–	–	(200)	(200)
Other investing activities	(1)	(15)	21	5
Net cash used in investing activities	(288)	(810)	(318)	(1,416)
Financing activities				
Issuance of common stock	304	–	–	304
Proceeds from issuance of long-term debt, net	–	935	604	1,539
Net decrease in short-term indebtedness	–	(258)	(438)	(696)
Retirement of long-term debt	–	(534)	(276)	(810)
Dividends paid on common stock	(541)	–	–	(541)
Dividends paid to parent	–	(301)	301	–
Changes in advances from affiliates	–	274	(274)	–
Contributions from parent	–	168	(168)	–
Other financing activities	–	–	16	16
Net cash (used) provided by financing activities	(237)	284	(235)	(188)
Cash provided (used) by discontinued operations				
Operating activities	–	123	–	123
Investing activities	–	(126)	–	(126)
Financing activities	–	–	–	–
Net decrease in cash and cash equivalents	(1)	(12)	(6)	(19)
Cash and cash equivalents at beginning of year	1	27	26	54
Cash and cash equivalents at end of year	$ –	$ 15	$ 20	$ 35

25. SUBSEQUENT EVENT

On January 25, 2006, we signed a definitive agreement to sell PT LLC to Level 3 Communications, Inc. (Level 3) for a purchase price of approximately $137 million, with half of the proceeds in cash and half in Level 3 common stock. We expect to use net cash proceeds of $70 million from the sale of our interest in PT LLC to reduce debt.

The sale is expected to close by mid-2006, and is subject to various closing conditions customary to such transactions. We expect to report PT LLC as a discontinued operation in the first quarter of 2006. The carrying amounts for the assets and liabilities of the discontinued operations disposal group included in the Consolidated Balance Sheets as of December 31 were as follows:

(in millions)	**2005**	2004
Total current assets	**$ 12**	$ 16
Total property, plant and equipment, net	**79**	75
Total other assets	**23**	39
Total current liabilities	**8**	15
Total long-term liabilities	**35**	34
Minority interest	**24**	21
Total capitalization	**47**	60

26. QUARTERLY FINANCIAL DATA (UNAUDITED)

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

Progress Energy

(in millions except per share data)	First (a)(b)	Second (a)(b)	Third (a)(b)	Fourth (a)(b)
2005				
Operating revenues	**$ 2,168**	**$ 2,295**	**$ 3,067**	**$ 2,578**
Operating income	**252**	**143**	**558**	**332**
Income from continuing operations before cumulative effect of changes in accounting principles	**104**	**7**	**459**	**157**
Net income	**93**	**(1)**	**450**	**155**
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting priciples	**0.43**	**0.03**	**1.86**	**0.63**
Net income	**0.38**	**(0.01)**	**1.82**	**0.62**
Diluted earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	**0.43**	**0.03**	**1.85**	**0.63**
Net income	**0.38**	**(0.01)**	**1.81**	**0.62**
Dividends declared per common share	**0.590**	**0.590**	**0.590**	**0.605**
Market price per share – High	**45.33**	**45.83**	**46.00**	**45.50**
– Low	**40.63**	**40.61**	**41.90**	**40.19**
2004				
Operating revenues	$ 1,987	$ 2,085	$ 2,445	$ 2,008
Operating income	283	288	567	306
Income from continuing operations before cumulative effect of changes in accounting principles	102	145	287	195
Net income	108	154	303	194
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	0.42	0.59	1.18	0.81
Net income	0.45	0.63	1.25	0.80
Diluted earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	0.42	0.59	1.18	0.81
Net income	0.45	0.63	1.24	0.80
Dividends declared per common share	0.575	0.575	0.575	0.590
Market price per share – High	47.95	47.50	44.32	46.10
– Low	43.02	40.09	40.76	40.47

(a) Operating results have been restated for discontinued operations.
(b) Certain amounts have been reclassified to conform with current period presentation.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. First quarter 2005 includes $31 million recorded for estimated severance expense for workforce restructuring and implementation of an automated meter reading initiative at PEF (See Note 17). Second quarter 2005 includes a $141 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 17). The 2004 amounts were restated for discontinued operations (See Notes 3A and 3B). Fourth quarter 2004 includes a $31 million after-tax gain on sale of natural gas assets (See Note 3E) and $90 million of Section 29 tax credits being recorded (See Note 23D). Third quarter 2004 includes reversal of $79 million of Section 29 tax credits (See Note 23D).

PEC

Summarized quarterly financial data was as follows:

(in millions)	First (a)	Second (a)	Third (a)	Fourth (a)
2005				
Operating revenues	**$ 935**	**$ 861**	**$ 1,185**	**$ 1,010**
Operating income	**221**	**140**	**343**	**227**
Net income	**116**	**67**	**184**	**126**
2004				
Operating revenues	$ 901	$ 862	$ 1,014	$ 852
Operating income	236	192	320	141
Net income	115	96	175	75

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

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. First quarter 2005 includes $14 million recorded for estimated severance expense for workforce restructuring (See Note 17). Second quarter 2005 includes a $29 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 17). Fourth quarter 2004 includes $99 million of Clean Smokestacks Act amortization. Fourth quarter 2003 includes impairment of investments of $21 million ($13 million after-tax) (See Note 7). Fourth quarter 2003 includes a cumulative effect for DIG Issue C20 of $38 million ($23 million after-tax) (See Note 13).

PEF

Summarized quarterly financial data was as follows:

(in millions)	First (a)	Second (a)	Third (a)	Fourth (a)
2005				
Operating revenues	**$ 848**	**$ 908**	**$ 1,227**	**$ 972**
Operating income	**89**	**51**	**247**	**112**
Net income	**44**	**10**	**151**	**55**
2004				
Operating revenues	$ 784	$ 860	$ 1,029	$ 852
Operating income	103	157	245	115
Net income	50	84	140	61

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

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. First quarter 2005 includes $14 million recorded for estimated severance expense for workforce restructuring and implementation of an automated meter reading initiative (See Note 17). Second quarter 2005 includes a $90 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 17).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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		(3,704,915)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		3,704,915		
4	Total (lines 2 and 3)		3,704,915		
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(78,616)		(3,783,531)		
2	8,621		8,621		
3			3,704,915		
4	8,621		3,713,536	334,882,384	338,595,920
5	(69,995)		(69,995)		
6	(69,995)		(69,995)		
7	15,250		15,250		
8	(56,824)		(56,824)		
9	(41,574)		(41,574)	259,708,903	259,667,329
10	(111,569)		(111,569)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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)	8,063,520,993	8,060,989,753
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	699,256,477	699,256,477
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	8,762,777,470	8,760,246,230
9	Leased to Others		
10	Held for Future Use	9,182,206	9,182,206
11	Construction Work in Progress	385,036,594	385,036,594
12	Acquisition Adjustments	17,054,019	17,054,019
13	Total Utility Plant (8 thru 12)	9,174,050,289	9,171,519,049
14	Accum Prov for Depr, Amort, & Depl	4,272,984,516	4,272,282,550
15	Net Utility Plant (13 less 14)	4,901,065,773	4,899,236,499
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,169,372,967	4,169,372,967
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	105,883,460	105,181,494
22	Total In Service (18 thru 21)	4,275,256,427	4,274,554,461
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	-2,271,911	-2,271,911
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,272,984,516	4,272,282,550

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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
	701,966				14
	1,829,274				15
					16
					17
					18
					19
					20
	701,966				21
	701,966				22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
	701,966				33

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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	415,230	436,724
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	415,230	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		51,723,077
9	In Reactor (120.3)	103,060,264	45,714,760
10	SUBTOTAL (Total 8 & 9)	103,060,264	
11	Spent Nuclear Fuel (120.4)		49,800,071
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	58,232,497	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	45,242,997	
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 Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
			2
		851,954	3
			4
			5
		851,954	6
			7
	45,612,836	6,110,241	8
	49,800,071	98,974,953	9
		105,085,194	10
		49,800,071	11
			12
-22,014,243		80,246,740	13
		75,490,479	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report 2005/Q4

FOOTNOTE DATA

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

$45,612,836 transferred to 120.3.

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

$49,800,071 transferred to 120.4.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	2,831,178	3,570,575
4	(303) Miscellaneous Intangible Plant	117,195,695	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	120,026,873	3,570,575
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	6,950,746	-500,432
9	(311) Structures and Improvements	285,244,615	374,108
10	(312) Boiler Plant Equipment	829,942,354	7,945,752
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	447,406,402	316,690
13	(315) Accessory Electric Equipment	158,087,753	539,242
14	(316) Misc. Power Plant Equipment	29,322,434	551,403
15	(317) Asset Retirement Costs for Steam Production		8,881,846
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,756,954,304	18,108,609
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	41,218	-192,136
19	(321) Structures and Improvements	219,366,347	2,060,114
20	(322) Reactor Plant Equipment	269,276,084	128,992
21	(323) Turbogenerator Units	91,748,483	368,420
22	(324) Accessory Electric Equipment	176,241,816	495,851
23	(325) Misc. Power Plant Equipment	40,631,042	-238,055
24	(326) Asset Retirement Costs for Nuclear Production	77,064,813	50,847
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	874,369,803	2,674,033
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	18,759,282	129,708
38	(341) Structures and Improvements	103,003,268	10,967,328
39	(342) Fuel Holders, Products, and Accessories	70,256,807	8,662,141
40	(343) Prime Movers	600,555,879	220,085,354
41	(344) Generators	261,332,083	50,073,096
42	(345) Accessory Electric Equipment	121,408,629	17,078,650
43	(346) Misc. Power Plant Equipment	14,422,012	3,914,096

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	12/31/2005	End of 2005/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
			6,401,753		3
			117,195,695		4
			123,597,448		5
					6
					7
			6,450,314		8
10,411			285,608,312		9
4,295,282			833,592,824		10
					11
747,132			446,975,960		12
200,868			158,426,127		13
7,035	-22,000		29,844,802		14
			8,881,846		15
5,260,728	-22,000		1,769,780,185		16
					17
			-150,918		18
787,294	-12,452		220,626,715		19
5,156,387			264,248,689		20
330,318			91,786,585		21
			176,737,667		22
318,445			40,074,542		23
	-77,064,814		50,846		24
6,592,444	-77,077,266		793,374,126		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			18,888,990		37
38,367	1,527,449		115,459,678		38
179,359			78,739,589		39
27,456,405	3,395,512		796,580,340		40
125,167			311,280,012		41
578,865			137,908,414		42
19,100			18,317,008		43

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,189,737,960	310,910,373
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,821,062,067	331,693,015
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	63,229,238	1,220,700
49	(352) Structures and Improvements	18,266,766	2,555,804
50	(353) Station Equipment	425,866,850	14,475,674
51	(354) Towers and Fixtures	69,046,102	21,382
52	(355) Poles and Fixtures	254,337,517	12,791,834
53	(356) Overhead Conductors and Devices	210,103,643	5,396,988
54	(357) Underground Conduit	7,010,980	
55	(358) Underground Conductors and Devices	9,496,402	
56	(359) Roads and Trails	1,923,606	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,059,281,104	36,462,382
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	21,658,350	13,796
61	(361) Structures and Improvements	20,784,605	1,595,246
62	(362) Station Equipment	349,071,366	12,294,658
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	425,999,599	18,086,166
65	(365) Overhead Conductors and Devices	462,721,647	38,835,416
66	(366) Underground Conduit	158,861,422	14,435,989
67	(367) Underground Conductors and Devices	427,037,054	17,689,792
68	(368) Line Transformers	402,803,897	27,580,732
69	(369) Services	416,422,796	30,355,312
70	(370) Meters	122,817,127	17,249,514
71	(371) Installations on Customer Premises	2,351,189	-129,039
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	247,772,163	17,541,389
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,058,301,215	195,548,971
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	11,394,794	-642,595
78	(390) Structures and Improvements	89,212,567	5,788,218
79	(391) Office Furniture and Equipment	15,025,489	-1,710,384
80	(392) Transportation Equipment	123,221,473	4,751,133
81	(393) Stores Equipment	3,106,750	260,382
82	(394) Tools, Shop and Garage Equipment	11,255,674	64,632
83	(395) Laboratory Equipment	3,632,223	104,834
84	(396) Power Operated Equipment	2,729,465	620,211
85	(397) Communication Equipment	69,300,583	4,132,290
86	(398) Miscellaneous Equipment	3,627,486	415,342
87	SUBTOTAL (Enter Total of lines 77 thru 86)	332,506,504	13,784,063
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		1,974,239
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	332,506,504	15,758,302
91	TOTAL (Accounts 101 and 106)	8,391,177,763	583,033,245
92	(102) Electric Plant Purchased (See Instr. 8)		
93	(Less) (102) Electric Plant Sold (See Instr. 8)		
94	(103) Experimental Plant Unclassified		
95	TOTAL Electric Plant in Service (Enter Total of lines 91 thru 94)	8,391,177,763	583,033,245

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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.
					44
28,397,263	4,922,961		1,477,174,031		45
40,250,435	-72,176,305		4,040,328,342		46
					47
9,943	166,804		64,606,799		48
161,304			20,661,266		49
5,081,687	-74,802		435,186,035		50
2,602,634			66,464,850		51
3,115,983			264,013,368		52
1,528,623			213,972,008		53
			7,010,980		54
			9,496,402		55
			1,923,606		56
					57
12,500,174	92,002		1,083,335,314		58
					59
201,914	332,244		21,802,476		60
91,955			22,287,896		61
4,447,528			356,918,496		62
					63
4,995,204			439,090,561		64
18,573,418	-379,000		482,604,645		65
885,898			172,411,513		66
2,875,330			441,851,516		67
19,499,197			410,885,432		68
12,960,149			433,817,959		69
6,080,787			133,985,854		70
			2,222,150		71
					72
5,674,923	7,463,208		267,101,837		73
					74
76,286,303	7,416,452		3,184,980,335		75
					76
61,253	-1,712		10,689,234		77
513,626	-62,329		94,424,830		78
2,841,995			10,473,110		79
			127,972,606		80
15,107			3,352,025		81
162,556			11,157,750		82
548,738			3,188,319		83
			3,349,676		84
16,002,824	308,710		57,738,759		85
414,143	55,558		3,684,243		86
20,560,242	300,227		326,030,552		87
					88
			1,974,239		89
20,560,242	300,227		328,004,791		90
149,597,154	-64,367,624		8,760,246,230		91
					92
					93
					94
149,597,154	-64,367,624		8,760,246,230		95

Schedule Page: 204 Line No.: 24 Column: e

ARO Liability was remeasured after the issuance of a new site-specific decommissioning cost study on 3/30/05. The result of the remeasurement indicated that the liability should be reduced.

Schedule Page: 204 Line No.: 95 Column: e

Amounts in column (e) represent adjustments to account 101 (Electric Plant in Service) and 101.3 (Intangible Plant).

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	PERRY - CROSS CITY - DUNNELLON	10/87	05/05	1,046,410
3	PERRY - FLORIDA STATE LINE	12/92	05/05	1,808,764
4	HIGH SPRINGS - JASPER - FLORIDA STATE LINE	03/96	05/05	2,584,486
5	BELCHER ROAD SUBSTATION	05/96	05/05	267,012
6	ST. PETERSBURG	12/05		1,760,000
7				
8	OTHER LAND RIGHTS	07/90	05/05	962,673
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	PERRY - CROSS CITY - DUNNELLON	07/90	05/05	752,861
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
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43				
44				
45				
46				
47	Total			9,182,206

Schedule Page: 214 Line No.: 6 Column: c

Date expected to be placed "In Service" is unknown at this time.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	HINES PB4-MASTER	109,197,945
2	STEAM GENERATOR REPLACEMENT	35,673,299
3	60KK8-1616T1 VANDOLAH-WHIDDEN	14,207,363
4	FPC EMS Upgrade Conversion	5,633,980
5	60KK8-1235S1 AVALON TRANSF	5,244,188
6	60KK8-1682T1 ATWATER-LIBERTY	4,997,186
7	60896 DIST OPS & SUPPORT BDGT	4,934,847
8	60KK8-1648T1 DEMPSEY (CFEC)	4,870,207
9	60440D SE ORLANDO OC-NEW	4,631,234
10	60KK8-1067T1 INGLIS CITRUS SPG	3,745,600
11	60KK8-1444S5 HINES PHASE III	3,694,076
12	60KK8-1179D1 DUNDEE TRANSF	3,477,636
13	605011682T2-JH LINE TO LOWRY	3,417,235
14	60GB9D ALTERNATE AC PWR MASTER	3,295,283
15	ANCL #2 L-O TURBINE BLADE REPLACEME	3,173,621
16	60KK8-1830T1 HINES PB4 H-WLW	3,022,338
17	60KK8-1489T4 HAINES CRK-TAV	2,963,455
18	60KK8-1698T1 GROVELAND (SECO)	2,902,777
19	60KK8-1666T1 TALLA-BRICKYARD	2,688,337
20	60440D ED VEH REPL TYPE E	2,428,512
21	60GB9D RB SUMP MASTER	2,398,444
22	60896 PQ&R	2,365,249
23	60KK8-1004T1 ICLB 69KV CIRCUIT	2,188,992
24	605011616S1 VANDOLAH TERM 230K	2,164,095
25	60208D TRIP TRANSFORMER PURCH	2,018,228
26	608961765D1 LAKE BRANCH SUB	2,007,180
27	608981200D1 CITRUS HILLS	1,854,824
28	60501392S6 WINDERMERE TRANSF	1,821,920
29	60896 MOBILE_LINK	1,653,361
30	60KK8-940T1 BI RELO FOR CR 486	1,600,778
31	608981025D1 POINCIANA	1,521,323
32	60KK8-1682S2 LIBERTY NEW SUB	1,501,161
33	60850D ST PETE GARAGE-NEW	1,390,562
34	60CR5CRP0 BOTTOM ASH REPL	1,283,659
35	60896 NO CENTRAL LRC	1,239,013
36	60379-INDIAN SHORES CONV	1,196,431
37	60CRN5CRP0 CR #5 FGD	1,191,190
38	60KK8-939T8 CSB RELO CR 491	1,185,755
39	60440D ED VEH REPL TYPE D	1,177,667
40	60898 TREASURE ISLAND	1,154,363
41	608961575D1 SUNFLOWER	1,119,665
42	608981769D1 BARNUM CITY	1,108,554
43	TOTAL	385,036,594

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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 HEAVY HAULING RD MATTING	1,095,295
2	CTE-TRE-0824D8-MOBILE	1,083,818
3	608961765T1 LAKE BRANCH LINE	1,061,227
4	REGUL STATE RD 500 (OBT)	1,040,518
5	Other Minor Projects	121,414,203
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
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41		
42		
43	TOTAL	385,036,594

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	4,095,202,183	4,095,202,183		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	269,678,438	269,678,438		
4	(403.1) Depreciation Expense for Asset Retirement Costs	373,504	373,504		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	6,594,772	6,594,772		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock - Oil	592,506	592,506		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	277,239,220	277,239,220		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	149,597,154	149,597,154		
13	Cost of Removal	59,429,428	59,429,428		
14	Salvage (Credit)	724,494	724,494		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	208,302,088	208,302,088		
16	Other Debit or Cr. Items (Describe, details in footnote):	5,233,652	5,233,652		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,169,372,967	4,169,372,967		

Section B. Balances at End of Year According to Functional Classification

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)
20	Steam Production	1,310,707,886	1,310,707,886		
21	Nuclear Production	564,803,794	564,803,794		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	462,980,057	462,980,057		
25	Transmission	453,026,610	453,026,610		
26	Distribution	1,252,165,798	1,252,165,798		
27	General	125,688,822	125,688,822		
28	TOTAL (Enter Total of lines 20 thru 27)	4,169,372,967	4,169,372,967		

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

Provision for Steam 311.0-315.0 & 316.3 Bartow-Anclote Pipeline.

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

Adjustments to Reserve:

Clearing Accounts	($7,187,278)
PTC Assets	8,411,134
Adjustments & Transfers	$4,009,796
Total	$5,233,652

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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)	103,298,488	135,760,761	Power Supply
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	94,036,240	129,576,400	Various
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	47,194,097	21,244,388	Power Supply
8	Transmission Plant (Estimated)	2,418,700	1,417,609	Transmission
9	Distribution Plant (Estimated)	11,602,490	4,256,302	Customer Service
10	Assigned to - Other (provide details in footnote)	1,136,699	510,511	Various
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	156,388,226	157,005,210	
12	Merchandise (Account 155)	204,989	259,681	Customer Service
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
15	Stores Expense Undistributed (Account 163)	19,516,453	9,156,997	Various
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	279,408,156	302,182,649	

Schedule Page: 227 Line No.: 11 Column: c

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

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

Schedule Page: 227 Line No.: 15 Column: b

Account 163- Stores Expense Undistributed was charged with $549,367 and credited with $312,959 for a net charge of $236,409 during 2004. These charges to operations, maintenance and capital accounts were to record various inventory adjustments for 2004.

Schedule Page: 227 Line No.: 15 Column: c

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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)	2006 No. (d)	2006 Amt. (e)
1	Balance-Beginning of Year	161,046.00	10,253,426	125,653.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Purchases AEP/TXU/BP	41,500.00	30,430,000		
10					
11					
12					
13					
14					
15	Total	41,500.00	30,430,000		
16					
17	Relinquished During Year:				
18	Charges to Account 509	154,536.00	31,061,622		
19	Other:				
20	True-ups	5,222.00	9,390		
21	Cost of Sales/Transfers:				
22	Sales	9.00	559		
23					
24					
25					
26					
27					
28	Total	9.00	559		
29	Balance-End of Year	42,779.00	9,611,855	125,653.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)	9.00	5,794		
33	Net Sales Proceeds (Other)				
34	Gains		5,235		
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)		1,198,954		
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	12/31/2005	End of 2005/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.

2007		2008		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
125,653.00		125,653.00		2,510,293.00		3,048,298.00	10,253,426	1
								2
								3
				119,141.00		119,141.00		4
								5
								6
								7
								8
			1,750			41,500.00	30,431,750	9
								10
								11
								12
								13
								14
			1,750			41,500.00	30,431,750	15
								16
								17
						154,536.00	31,061,622	18
								19
				-91.00		5,131.00	9,390	20
								21
						9.00	559	22
								23
								24
								25
								26
								27
						9.00	559	28
125,653.00		125,653.00	1,750	2,629,525.00		3,049,263.00	9,613,605	29
								30
								31
						9.00	5,794	32
								33
							5,235	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
					523,619		1,722,573	44
								45
								46

Schedule Page: 228 Line No.: 20 Column: a

True-Up required for Accounting Reconciliation.

Schedule Page: 228 Line No.: 20 Column: c

Footnote Linked. See note on 228, Row: 20, col/item:

Schedule Page: 228 Line No.: 20 Column: j

Footnote Linked. See note on 228, Row: 20, col/item:

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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 expense consistent					
5	with recovery in rates)	16,963,061	4,317,290	4073701	434,000	16,529,061
6						
7	Storm Extraordinary Property Loss					
8	Retail-(FPSC Order No. PSC-05-					
9	0748-FOF-EI Docket No. 041272-EI					
10	amortization over two years).	240,759,265	240,759,265	4070003	50,486,892	190,272,373
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL	257,722,326	245,076,555		50,920,892	206,801,434

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Accumulated Deferred Taxes - FAS 109	109,055,000	1,144,000	4101000	1,325,000	108,874,000
2	Period of Amortization - Amortization occurs					
3	as temporary differences occur.					
4						
5	Nuclear Decom/Decontamination	3,711,206	300,388	5188200	2,018,235	1,993,359
6	Amortization Period = 12 months					
7						
8	Load Control Switches - Investment	3,349,752	777,799	1861902	1,001,135	3,126,416
9	Load Control Switches - Amortization	(1,588,226)	730,341	9080120	654,055	-1,511,940
10						
11	Deferred Energy Conservation Expense	(8,126,534)	4,584,991	9080110	6,056,715	-9,598,258
12						
13	Sebring Transition Rider	11,739,205	18,707	1861904	2,999,998	8,757,914
14	Sebring - Over(Under) Recovered	(1,332,410)	2,999,997	4044002	2,857,324	-1,189,737
15						
16	Interest on Tax Deficiency	894,428	808,429	4310024	1,283,748	419,109
17						
18	Deferred GPIF Asset	2,139,695	532,353	4560096	2,139,695	532,353
19						
20	Deferred Fuel Expense - Full Req	5,056,757	15,488,396	5572002	8,056,396	12,488,757
21	Deferred Fuel Expense - 01/04 - 12/04	170,405,450		5572002	91,248,180	79,157,270
22	Deferred Fuel Expense - 01/05 - 12/05		236,919,841	5572002		236,919,841
23	Deferred Capacity Expense - 01/05 - 12/05		29,250,771	5572002	17,053,032	12,197,739
24						
25	Deferred Environmental Cost Recovery	12,113,943	2,908,626	9350003	8,824,978	6,197,591
26	Accrued Environmental Cost Recovery	26,402,500	444,142	2284800	7,537,642	19,309,000
27						
28	RTO Set Up Costs	4,236,899	282,911	5660000	9,702	4,510,108
29						
30	Florida Minimum Pension Liability	7,153,634	24,896,475	2283151	24,828,394	7,221,715
31						
32	Regulatory Asset Derivative MTM Oil	5,183,190	13,232,753	2543015-7	12,311,051	6,104,892
33						
34	Regulatory Asset - FAS 143 Asbestos		187,999			187,999
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	350,394,489	335,508,919		190,205,280	495,698,128

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	719	928,224	Various	922,356	6,587
2						
3	FMS Solution Store Sell	170,952		923	170,952	
4						
5	GE Turbine Transaction	29,584,281		154	29,584,281	
6						
7	Major Storm Bonnie	90,045		Various	90,045	
8						
9	Hurricane Charley	124,939,838		Various	124,939,838	
10						
11	Hurricane Ivan	8,203,763		Various	8,203,763	
12						
13	Hurricane Francis	118,748,354		Various	118,748,354	
14						
15	Major Storms Final Sweeps	11,100,099		Various	11,100,099	
16						
17	Southern Company Capacity Dep	803,433				803,433
18						
19	Wholesale Storm Reclass	-12,645,771	12,645,771			
20						
21	Hurricane Jeanne	75,131,992		Various	75,131,992	
22						
23	Vacation Pay Accrual	7,611,131	4,163,303	242	7,611,131	4,163,303
24						
25	Florida Rate Case		1,844,213			1,844,213
26						
27	Homosassa Fuel Cell		346,058		132,540	213,518
28						
29	Longwood Hydrogen Vehicle		298,772		180,568	118,204
30						
31	Hurricane Dennis		4,052,087	Various	1,531,623	2,520,464
32						
33	Hurricane Katrina		1,424,586	Various	159,382	1,265,204
34						
35	Hurricane Katrina Off System		989,457	Various	1,828	987,629
36						
37	Katrina Cleco Assist		638,686	Various	3,424	635,262
38						
39	Katrina Entergy Assist		1,688,120	Various	199,462	1,488,658
40						
41	Rita Entergy Off System		3,353,553	Various	8,363	3,345,190
42						
43	Hurricane Wilma		4,531,057	Various	565,605	3,965,452
44						
45	Wilma FPL Off System		1,689,091	Various	4,148	1,684,943
46	Oil Swap		5,000,000			5,000,000
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	365,126,350				30,456,477

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	Labor Accrual	1,387,514	1,168,180	402	1,387,514	1,168,180
2						
3	Minimum Pension Liability		1,246,237			1,246,237
4						
5						
6						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	365,126,350				30,456,477

Schedule Page: 233 Line No.: 1 Column: b

Certain 2004 amounts were reclassified to conform with 2005 presentation.

Schedule Page: 233.1 Line No.: 1 Column: b

Certain 2004 amounts were reclassified to conform with 2005 presentation.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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	34,726,000	30,121,000
3	LIFE/MEDICAL BENEFITS	62,702,000	70,276,000
4	UNAMORTIZED INVESTMENT TAX CREDIT	13,648,000	11,532,000
5	REGULATORY LIABILITY	23,195,000	19,362,000
6	NUCLEAR DECOMMISSIONING	37,910,000	44,077,000
7	OTHER	-4,902,596	25,689,047
8	TOTAL Electric (Enter Total of lines 2 thru 7)	167,278,404	201,057,047
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)	167,278,404	201,057,047

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	12/31/2005	End of 2005/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	60,000,000		
2	Total Common Stock	60,000,000		
3	Cumulative Preferred Stock	4,000,000		
4	4.00% Series		100.00	104.25
5	4.60% Series		100.00	103.25
6	4.75% Series		100.00	102.00
7	4.40% Series		100.00	102.00
8	4.58% Series		100.00	101.00
9	Cumulative Preferred Stock	5,000,000		
10	Preference Stock	1,000,000	100.00	
11	Total Preferred Stock	10,000,000		
12				
13				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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 from 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	193,270
25	Misc PIC - Stock Options	401,711
26	Misc PIC - Performance Share Sub Plan (PSSP)	311,642
27		
28		
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39		
40	TOTAL	742,267,894

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	FIRST MORTGAGE BONDS - 6.65%	300,000,000	3,182,657
2			429,000 D
3	FIRST MORTGAGE BONDS - 6 7/8%	80,000,000	765,503
4			1,069,599 D
5	FIRST MORTGAGE BONDS - 4.8%	425,000,000	4,585,299
6			1,513,000 D
7	FIRST MORTGAGE BONDS - 5.9%	225,000,000	3,013,280
8			571,500 D
9	FIRST MORTGAGE BONDS - 5.1%	300,000,000	3,473,110
10			594,000 D
11	FIRST MORTGAGE BONDS - 4.5%	300,000,000	1,457,295
12			2,115,000 D
13	MEDIUM TERM NOTE (SEBRING) - 6.67%	30,700,000	280,604
14			
15	MEDIUM TERM NOTE - 6.72%	45,000,000	272,183
16			
17	MEDIUM TERM NOTE - 6.77%	45,000,000	271,939
18			
19	MEDIUM TERM NOTE - 6.81%	85,000,000	534,680
20			
21	MEDIUM TERM NOTE - 6.75%	150,000,000	5,528,498
22			436,500 D
23	SERIES A SENIOR NOTE - FLOATING RATE	450,000,000	656,125
24			1,575,000 D
25	POLLUTION CONTROL BONDS (CITRUS) 2002A	108,550,000	2,356,705
26			
27	POLLUTION CONTROL BONDS (CITRUS) 2002B	100,115,000	2,081,983
28			
29	POLLUTION CONTROL BONDS (CITRUS) 2002C	32,200,000	756,175
30			
31	RCA 3 YEAR	55,000,000	524,500 D
32	RCA 5 YEAR		990,975 D
33	TOTAL	2,731,565,000	39,035,110

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
071801	071511	071801	071511	300,000,000	19,950,000	1
						2
020993	020108	020993	020108	80,000,000	5,500,004	3
						4
022103	030113	022103	030113	425,000,000	20,400,000	5
						6
022103	030133	022103	030133	225,000,000	13,275,000	7
						8
112103	120115	112103	120115	300,000,000	15,300,000	9
						10
051605	060110	051605	060110	300,000,000	8,437,500	11
						12
042093	040108	042093	040108	8,800,005	687,011	13
						14
072597	070105	072597	070105		1,512,000	15
						16
072597	070106	072597	070106	45,000,000	3,046,500	17
						18
072597	070107	072597	070107	85,000,000	5,788,500	19
						20
021398	020128	021398	020128	150,000,000	10,125,000	21
						22
121305	111408	121305	111408	450,000,000	1,161,672	23
						24
082002	010127	082002	010127	108,550,000	2,582,405	25
						26
072402	010122	072402	010122	100,115,000	2,262,719	27
						28
081302	010118	081302	010118	32,200,000	766,350	29
						30
040103	040106	040103	040106		162,553	31
032805	032810	032805	032810			32
				2,609,665,005	110,957,214	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	12/31/2005	End of 2005/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)	259,708,903
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	101,970,713
11		
12	Deductions Recorded on Books Not Deducted for Return	564,655,748
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	-496,093,064
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	430,242,300
28	Show Computation of Tax:	
29	Provision for Federal Income Tax at 35%	150,584,806
30	True up Entries and Other Tax Benefits	4,608,166
31	Total Federal Income Tax Provision (409120F - 409220F) True up Entries	145,976,640
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	12/31/2005	End of 2005/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	28,191,376		145,976,641	169,384,039	-1,058,331
3	FICA			22,612,805	22,014,919	
4	Unemployment			291,294	268,629	
5	Special Fuel Tax	-1,137,939				1,137,939
6	Excise Tax					
7	Highway Use			36,147	36,147	
8	Payroll Tax	2,003,141			270,698	
9	SUBTOTAL	29,056,578		168,916,887	191,974,432	79,608
10						
11	STATE TAXES					
12	Income	-7,227,187		25,477,875	15,357,023	-79,608
13	Income Tax Subsidiary					
14	Gross Receipts	6,008,984		85,155,533	78,436,589	
15	Unemployment	198		1,965,818	1,813,029	
16	Intangibles			26,627	26,627	
17	Regulatory Assessment	1,215,271		2,549,042	2,338,704	
18	Sales Tax-Company Use	14,147		150,588	152,736	
19	SUBTOTAL	11,413		115,325,483	98,124,708	-79,608
20						
21	COUNTY & LOCAL TAXES					
22	Property-County & Local	3,274,429		88,564,834	88,496,200	
23	FL Privilege License			7,769	7,769	
24	Franchise-Local	6,098,838		81,803,735	81,461,316	
25						
26						
27	Adj-Use Tax on Purchases					
28	SUBTOTAL	9,373,267		170,376,338	169,965,285	
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	38,441,258		454,618,708	460,064,425	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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
3,725,647		154,744,964			-8,768,323	2
597,886		20,385,736			2,227,069	3
22,665					291,294	4
						5
						6
		36,147				7
1,732,443						8
6,078,641		175,166,847			-6,249,960	9
						10
						11
2,814,057		26,045,841			-567,966	12
						13
12,727,927		85,155,533				14
152,987					1,965,818	15
		26,627				16
1,425,609		2,549,042				17
11,999		150,588				18
17,132,579		113,927,631			1,397,852	19
						20
						21
3,343,064		88,394,555			170,279	22
		7,769				23
6,441,257		81,803,735				24
						25
						26
						27
9,784,321		170,206,059			170,279	28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
32,995,541		459,300,537			-4,681,829	41

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

The difference between the taxes accrued amount on page 112, line 37 and taxes accrued on page 262 - 263, Col.(b)&(g) are for exclusions of sales taxes per instruction #1 on page 262.

	Balance at Beginning of Year	Balance at End of Year
Taxes Accrued, P.112, Line 37	38,585,326	33,505,144
State Sales Tax on Purchases	(140,812)	(504,923)
County Sales Tax on Purchases	(3,256)	(4,681)
	38,441,258	32,995,540

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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%	35,280,508			4114001	5,484,000	
6							
7							
8	TOTAL	35,280,508				5,484,000	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
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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	12/31/2005	End of 2005/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
29,796,508	27 years		5
			6
			7
29,796,508			8
			9
			10
			11
			12
			13
			14
			15
			16
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			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	12/31/2005	End of 2005/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	FAS 146 Deferred Exit Costs	1,722,453	131	566,212	112,758	1,268,999
2	Wholesale Deposits - SECI	4,770,000			580,000	5,350,000
3	Wholesale Deposits - Mirant	6,000,000				6,000,000
4	Wholesale Deposits - Other	368,463	various	250,135	531	118,859
5	Wholesale Deposits - FMPA	1,220,000	131	230,000		990,000
6	Winter Park Standard Costs		456	31,931,020	38,445,000	6,513,980
7	Derivative Premiums				43,151,300	43,151,300
8	Deferred Rent Expenses	583,342	931	113,981		469,361
9	Cable and Other Deposits	761,627	131	10,330,419	9,934,090	365,298
10	Collateral Held Oil Swap		131	34,070,000	52,450,000	18,380,000
11	Franchise Settlements				2,442,000	2,442,000
12	Grid Florida RTO Recoveries				5,817,388	5,817,388
13	St. Pete Land Commitment				1,700,000	1,700,000
14	Joint Owner	894,437	various	10,278,796	9,826,265	441,906
15	Various	156,608	various	4,409,170	4,374,949	122,387
16						
17						
18						
19						
20						
21						
22						
23						
24						
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36						
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39						
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41						
42						
43						
44						
45						
46						
47	TOTAL	16,476,930		92,179,733	168,834,281	93,131,478

Schedule Page: 269 Line No.: 9 Column: b

Certain 2004 amounts were reclassified to conform with 2005 presentations.

Schedule Page: 269 Line No.: 14 Column: b

Certain 2004 amounts were reclassified to conform with 2005 presentations.

Schedule Page: 269 Line No.: 15 Column: b

Certain 2004 amounts were reclassified to conform with 2005 presentations.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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		996,000
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	6,186,000		996,000
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		996,000
18	Classification of TOTAL			
19	Federal Income Tax	5,306,000		852,000
20	State Income Tax	880,000		144,000
21	Local Income Tax			

NOTES

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
						5,190,000	4
							5
							6
							7
						5,190,000	8
							9
							10
							11
							12
							13
							14
							15
							16
						5,190,000	17
							18
						4,454,000	19
						736,000	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	12/31/2005	End of 2005/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	435,312,618	-1,310,024	12,767,000
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	435,312,618	-1,310,024	12,767,000
6	Other - Transfer of PVI turbin			
7	Other - balance sheet reclass			
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	435,312,618	-1,310,024	12,767,000
10	Classification of TOTAL			
11	Federal Income Tax	374,095,242	-1,517,151	10,453,809
12	State Income Tax	61,217,376	207,127	2,313,191
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
19,216,000	10,439,000	409.1	650,000			429,362,594	2
							3
							4
19,216,000	10,439,000		650,000			429,362,594	5
				154.2	8,821,197	8,821,197	6
							7
							8
19,216,000	10,439,000		650,000		8,821,197	438,183,791	9
							10
16,476,000	8,951,000		557,000		7,829,280	376,921,562	11
2,740,000	1,488,000		93,000		991,917	61,262,229	12
							13

NOTES (Continued)

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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	42,061,000		71,000
4				
5				
6	OCI / Min. Pension Liability -	2,759,514		
7				
8	Other	128,412,000	36,351,893	41,422,000
9	TOTAL Electric (Total of lines 3 thru 8)	173,232,514	36,351,893	41,493,000
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)	173,232,514	36,351,893	41,493,000
20	Classification of TOTAL			
21	Federal Income Tax	148,586,064	31,295,993	35,629,955
22	State Income Tax	24,646,450	5,055,900	5,863,045
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						41,990,000	3
							4
							5
				190.1	10,219,378	12,978,892	6
							7
						123,341,893	8
					10,219,378	178,310,785	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
					10,219,378	178,310,785	19
							20
					8,762,305	153,014,407	21
					1,457,073	25,296,378	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	60,282,516	4111000	11,519,000	1,428,000	50,191,516
2	Period of Amortization occurs as					
3	temporary differences occur.					
4						
5	Deferred Capacity Rev - 01/04 - 12/04	7,661,393	5572001	10,411,682	2,750,289	
6						
7	Auctioned S02 Allowances	2,397,820			1,722,573	4,120,393
8						
9	ARO - Nuclear Decom Trust Unr Gains	98,857,536	1289191	31,038,349	47,922,977	115,742,164
10	ARO - SFAS 143 Nuclear Decom	25,753,489	4073002	15,787,230	66,607,048	76,573,307
11	ARO - SFAS 143 Asbestos Reg Liab				3,743,818	3,743,818
12						
13	Derivative Liability - MTM Oil	2,400,444	1763015-7	902,017,399	1,022,026,261	122,409,306
14						
15						
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19						
20						
21						
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26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	197,353,198		970,773,660	1,146,200,966	372,780,504

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	2,000,607,080	1,806,251,665
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	948,550,111	853,365,829
5	Large (or Ind.) (See Instr. 4)	284,365,436	253,958,706
6	(444) Public Street and Highway Lighting	1,645,750	1,491,794
7	(445) Other Sales to Public Authorities	240,205,452	209,034,575
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,475,373,829	3,124,102,569
11	(447) Sales for Resale	345,510,905	268,335,401
12	TOTAL Sales of Electricity	3,820,884,734	3,392,437,970
13	(Less) (449.1) Provision for Rate Refunds	2,289,386	11,269,477
14	TOTAL Revenues Net of Prov. for Refunds	3,818,595,348	3,381,168,493
15	Other Operating Revenues		
16	(450) Forfeited Discounts	10,615,943	8,582,058
17	(451) Miscellaneous Service Revenues	23,990,748	22,416,292
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	63,360,062	62,537,903
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	47,440,245	51,927,645
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	145,406,998	145,463,898
27	TOTAL Electric Operating Revenues	3,964,002,346	3,526,632,391

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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
19,893,534	19,347,267	1,397,013	1,364,676	2
				3
11,944,716	11,733,536	161,001	158,780	4
4,139,872	4,068,627	2,703	2,733	5
27,388	27,927	1,795	1,856	6
3,171,076	3,015,746	20,879	20,557	7
				8
				9
39,176,586	38,193,103	1,583,391	1,548,602	10
5,456,086	5,100,847	26	25	11
44,632,672	43,293,950	1,583,417	1,548,627	12
				13
44,632,672	43,293,950	1,583,417	1,548,627	14

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SERVICE	19,893,534	2,000,607,080	1,397,013	14,240	0.1006
2						
3	COMMERCIAL & IND SERVICE	16,084,588	1,232,915,547	163,704	98,254	0.0767
4						
5	PUBLIC STREET AND HIGHWAY					
6	LIGHTING	27,388	1,645,750	1,795	15,258	0.0601
7						
8	OTHER SALES TO PUBLIC					
9	AUTHORITIES	3,171,076	240,205,452	20,879	151,879	0.0757
10						
11	TOTAL SALES TO ULTIMATE	39,176,586	3,475,373,829	1,583,391	24,742	0.0887
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	12/31/2005	End of 2005/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	REQUIREMENT SERVICE					
2	CITY OF BARTOW	RQ	TARIFF NO. 9	56	56	56
3	CITY OF CHATTAHOOCHEE	RQ	FERC NO. 126	6	6	5
4	CITY OF HOMESTEAD	RQ	TARIFF NO. 9	15	15	15
5	CITY OF KISSIMMEE	RQ	FERC NO. 120			
6	CITY OF MOUNT DORA	RQ	FERC NO. 127	20	20	20
7	CITY OF NEWBERRY	RQ	FERC NO. 116	6	6	6
8	CITY OF NEW SMYRNA BEACH	RQ	FERC NO. 144	49	49	49
9	CITY OF QUINCY	RQ	TARIFF NO. 1	21	21	17
10	CITY OF ST CLOUD	RQ	FERC NO. 121	11	11	11
11	CITY OF TALLAHASSEE	RQ	FERC NO. 178	39	39	39
12	CITY OF WILLISTON	RQ	FERC NO. 124	6	6	6
13	CITY OF WINTER PARK	RQ	FERC NO. 191	91	91	88
14	FLORIDA MUNICIPAL POWER AGENCY	RQ	FERC NO. 107	23	18	18
	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) 12/31/2005	Year/Period of Report End of 2005/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
298,173	6,360,221	12,595,653	18,720	18,974,594	2
34,204	672,284	1,387,358	3,168	2,062,810	3
130,213	2,520,000	3,970,182		6,490,182	4
			8,004	8,004	5
101,000	2,233,607	4,290,853	3,168	6,527,628	6
29,817	681,219	1,564,363	3,168	2,248,750	7
302,407	3,528,060	14,159,632	996	17,688,688	8
116,845	2,323,821	4,931,582	6,336	7,261,739	9
			996	996	10
338,461	2,426,968	15,225,726		17,652,694	11
33,178	725,633	1,432,366	3,168	2,161,167	12
258,619	4,532,649	14,653,910		19,186,559	13
153,908	3,573,564	7,002,079	71,040	10,646,683	14
5,195,238	86,189,865	241,343,567	1,057,298	328,590,730	
260,848	0	17,025,926	-105,751	16,920,175	
5,456,086	**86,189,865**	**258,369,493**	**951,547**	**345,510,905**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	FLORIDA POWER AND LIGHT	RQ	TARIFF No. 9	150	150	135
2	REEDY CREEK IMPROVEMENT DISTRICT	RQ	FERC NO. 118			
3	SEMINOLE ELECTRIC COOPERATIVE, INC	RQ	FERC NO. 106	530	707	546
4	SOUTHEASTERN POWER ADMIN	RQ	FERC NO. 65	15	11	6
5	TAMPA ELECTRIC COMPANY	RQ	FERC NO. 7	158	158	146
6						
7						
8						
9	NON-REQUIREMENTS SERVICE					
10	ALABAMA ELECTRIC CO-OP	OS	FERC NO. 148			
11	AMERICAN ELECTRIC POWER CO	OS	FERC NO. 9			
12	COBB ELECTRIC MEMBERSHIP CORP	OS	FERC NO. 10			
13	CARGILL-ALLIANT	OS	FERC NO. 8			
14	DTE ENERGY TRADING	OS	FERC NO. 176			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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.
544,350	6,676,500	15,576,083		22,252,583	1
			33,984	33,984	2
1,619,840	41,435,109	88,239,237	904,550	130,578,896	3
16,759	445,620	493,507		939,127	4
1,217,464	8,054,610	55,821,036		63,875,646	5
					6
					7
					8
					9
5,865		253,434		253,434	10
100		6,722		6,722	11
32,954		1,986,488		1,986,488	12
50		1,933		1,933	13
100		6,788		6,788	14
5,195,238	86,189,865	241,343,567	1,057,298	328,590,730	
260,848	0	17,025,926	-105,751	16,920,175	
5,456,086	**86,189,865**	**258,369,493**	**951,547**	**345,510,905**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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)	Average Monthly CP Demand (f)
1	DUKE POWER COMPANY	OS	FERC NO. 10			
2	FLORIDA MUNICIPAL POWER AGENCY	OS	FERC NO. 105			
3	FLORIDA POWER & LIGHT CO	OS	FERC NO. 81/02			
4	GAINESVILLE REGIONAL UTILITIES	OS	FERC NO. 88			
5	HOMESTEAD, CITY OF	OS	FERC NO. 82			
6	LAKELAND, CITY OF	OS	FERC NO 92			
7	NEW SMYRNA BEACH, CITY OF (1)	OS	FERC NO. 104			
8	OGLETHORPE	OS	FERC NO. 139			
9	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86			
10	PJM INTERCONNECTION, LLC	OS	PJM			
11	REEDY CREEK UTILITIES (1)	OS	FERC NO. 119			
12	SOUTH CAROLINA ELEC & GAS CO	OS	FERC NO. 8/10			
13	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128			
14	SOUTHERN COMPANY SERVICES	OS	FERC NO. 111			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
300		33,489		33,489	1
9,715		551,680		551,680	2
10,375		666,153		666,153	3
265		25,681		25,681	4
555		31,486		31,486	5
1,800		103,390		103,390	6
		130,793	-50,465	80,328	7
16,622		851,517		851,517	8
2,348		129,998		129,998	9
17,727		1,385,411		1,385,411	10
1,080		120,875	-55,286	65,589	11
100		6,972		6,972	12
57,217		4,394,800		4,394,800	13
28,517		1,597,296		1,597,296	14
5,195,238	86,189,865	241,343,567	1,057,298	328,590,730	
260,848	0	17,025,926	-105,751	16,920,175	
5,456,086	**86,189,865**	**258,369,493**	**951,547**	**345,510,905**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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	TALLAHASSEE, CITY OF	OS	FERC NO. 122			
2	THE ENERGY AUTHORITY	OS	FERC NO. 175			
3	TAMPA ELECTRIC CO	OS	FERC NO. 80			
4	TENNESSEE VALLEY AUTHORITY	OS	FERC NO. 138			
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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.
1,688		170,104		170,104	1
19,123		1,164,566		1,164,566	2
40,373		2,471,871		2,471,871	3
13,974		934,479		934,479	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
5,195,238	86,189,865	241,343,567	1,057,298	328,590,730	
260,848	0	17,025,926	-105,751	16,920,175	
5,456,086	**86,189,865**	**258,369,493**	**951,547**	**345,510,905**	

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

Non-requirement Service is either:
(1) Economy Interchanges Sales for
pages 310.1 lines 9-14,
pages 310.2 lines 1-14,
pages 310.3 lines 1-5 and 7-9

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

Schedule Page: 310.2 Line No.: 7 Column: a

2005 OS Sales for New Symrna Beach includes ($50,465) capacity credit.

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

2004 OS Sales for Reedy Creek includes ($55,286) capacity credit.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,541,810	1,638,299
5	(501) Fuel	792,443,798	658,062,830
6	(502) Steam Expenses	8,287,694	8,605,612
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	8,087	1,377
10	(506) Miscellaneous Steam Power Expenses	25,218,350	23,736,541
11	(507) Rents		
12	(509) Allowances	31,061,621	15,238,599
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	858,561,360	707,283,258
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,781,214	3,463,905
16	(511) Maintenance of Structures	1,609,815	1,436,117
17	(512) Maintenance of Boiler Plant	9,310,082	5,669,657
18	(513) Maintenance of Electric Plant	4,415,005	4,459,967
19	(514) Maintenance of Miscellaneous Steam Plant	26,965,809	27,762,455
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	46,081,925	42,792,101
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	904,643,285	750,075,359
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	157,350	6,245
25	(518) Fuel	30,902,753	33,969,862
26	(519) Coolants and Water	3,607,835	2,681,868
27	(520) Steam Expenses	11,553,683	9,274,582
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	11,700	3,764
31	(524) Miscellaneous Nuclear Power Expenses	34,665,696	31,821,923
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	80,899,017	77,758,244
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	13,145,056	11,954,981
36	(529) Maintenance of Structures	897,761	1,172,871
37	(530) Maintenance of Reactor Plant Equipment	18,690,742	13,057,074
38	(531) Maintenance of Electric Plant	2,482,936	2,614,233
39	(532) Maintenance of Miscellaneous Nuclear Plant	2,562,762	1,455,013
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	37,779,257	30,254,172
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	118,678,274	108,012,416
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)		

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintentance 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)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	14,120,367	8,387,170
63	(547) Fuel	665,406,008	452,395,718
64	(548) Generation Expenses	4,341,600	4,222,951
65	(549) Miscellaneous Other Power Generation Expenses	6,919,354	6,551,272
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	690,787,329	471,557,111
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	382,150	353,726
70	(552) Maintenance of Structures	182,878	322,172
71	(553) Maintenance of Generating and Electric Plant	1,827,297	2,470,207
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	9,338,883	13,146,375
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	11,731,208	16,292,480
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	702,518,537	487,849,591
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	714,065,625	568,665,170
77	(556) System Control and Load Dispatching	5,755,496	5,065,817
78	(557) Other Expenses	44,086	23,498
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	719,865,207	573,754,485
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,445,705,303	1,919,691,851
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,204,862	2,606,417
84	(561) Load Dispatching	410,477	380,979
85	(562) Station Expenses	352,674	182,772
86	(563) Overhead Lines Expenses	405,758	312,673
87	(564) Underground Lines Expenses		
88	(565) Transmission of Electricity by Others		2,759
89	(566) Miscellaneous Transmission Expenses	18,079,300	12,743,948
90	(567) Rents		300
91	TOTAL Operation (Enter Total of lines 83 thru 90)	21,453,071	16,229,848
92	Maintenance		
93	(568) Maintenance Supervision and Engineering		
94	(569) Maintenance of Structures		40,525
95	(570) Maintenance of Station Equipment	1,653,870	1,332,660
96	(571) Maintenance of Overhead Lines	7,238,079	8,376,124
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	1,998,892	736,875
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	10,890,841	10,486,184
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	32,343,912	26,716,032
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	8,573,917	6,612,559

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	3,946,840	4,081,995
106	(582) Station Expenses	494,031	276,504
107	(583) Overhead Line Expenses	1,318,912	4,711,997
108	(584) Underground Line Expenses	1,275,124	2,156
109	(585) Street Lighting and Signal System Expenses	4,085,711	5,265,171
110	(586) Meter Expenses	6,439,872	7,300,276
111	(587) Customer Installations Expenses	598,214	542,332
112	(588) Miscellaneous Expenses	34,483,616	28,592,023
113	(589) Rents	3,286,262	1,611,026
114	TOTAL Operation (Enter Total of lines 103 thru 113)	64,502,499	58,996,039
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	1,866,021	115,461
117	(591) Maintenance of Structures	41,130	31,305
118	(592) Maintenance of Station Equipment	2,282,389	1,792,763
119	(593) Maintenance of Overhead Lines	44,201,168	16,320,272
120	(594) Maintenance of Underground Lines	9,655,614	302,478
121	(595) Maintenance of Line Transformers	118,994	302,881
122	(596) Maintenance of Street Lighting and Signal Systems		
123	(597) Maintenance of Meters	638,647	13,207
124	(598) Maintenance of Miscellaneous Distribution Plant	8,051,040	7,069,177
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	66,855,003	25,947,544
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	131,357,502	84,943,583
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	1,225,085	1,802,026
130	(902) Meter Reading Expenses	10,006,780	8,486,087
131	(903) Customer Records and Collection Expenses	24,435,177	23,707,780
132	(904) Uncollectible Accounts	9,639,255	4,977,560
133	(905) Miscellaneous Customer Accounts Expenses	8,627,153	10,474,852
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	53,933,450	49,448,305
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	711,996	
138	(908) Customer Assistance Expenses	60,193,967	60,850,845
139	(909) Informational and Instructional Expenses	2,905,644	3,031,326
140	(910) Miscellaneous Customer Service and Informational Expenses	64,274	240,774
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	63,875,881	64,122,945
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	13,152	10,869
145	(912) Demonstrating and Selling Expenses	1,990,109	1,454,044
146	(913) Advertising Expenses	31,045	527,422
147	(916) Miscellaneous Sales Expenses	329,976	247,033
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	2,364,282	2,239,368
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	56,148,675	73,601,224
152	(921) Office Supplies and Expenses	31,422,436	23,166,810
153	(Less) (922) Administrative Expenses Transferred-Credit		

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	30,647,789	28,363,031
156	(924) Property Insurance	10,496,182	10,655,759
157	(925) Injuries and Damages	18,199,749	6,879,262
158	(926) Employee Pensions and Benefits	145,835,191	34,349,838
159	(927) Franchise Requirements		
160	(928) Regulatory Commission Expenses		2,358
161	(929) (Less) Duplicate Charges-Cr.	433,114	600,454
162	(930.1) General Advertising Expenses	2,237,207	3,367,747
163	(930.2) Miscellaneous General Expenses	5,393,992	399,042
164	(931) Rents	6,273,692	7,950,036
165	TOTAL Operation (Enter Total of lines 151 thru 164)	306,221,799	188,134,653
166	Maintenance		
167	(935) Maintenance of General Plant	8,908,433	783,982
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	315,130,232	188,918,635
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	3,044,710,562	2,336,080,719

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PURCHASED POWER:					
2	SOUTHEASTERN POWER ADM	OS	FERC NO. 65	N/A	N/A	N/A
3	GLADES ELECTRIC COOPERATIVE INC.	OS	*	N/A	N/A	N/A
4	AUBURNDALE POWER PARTNERS (1)	OS	COG	123	155	105
5	AUBURNDALE POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
6	BAY COUNTY(1)	OS	COG	8	10	8
7	BAY COUNTY (1)	AD	COG	N/A	N/A	N/A
8	CARGILL FERTILIZER (1)	OS	COG	15	38	12
9	CARGILL FERTILIZER (1)	AD	COG	N/A	N/A	N/A
10	CITRUS WORLD (1)	OS	COG	N/A	1	0
11	CITRUS WORLD (1)	AD	COG	N/A	N/A	N/A
12	JEFFERSON POWER L.C. (1)	OS	COG	1	4	1
13	JEFFERSON POWER L.C. (1)	AD	COG	N/A	N/A	N/A
14	LAKE COUNTY (1)	OS	COG	11	19	10
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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
53,618				1,504,436		1,504,436	2
119				12,921		12,921	3
591,833			35,162,543	17,282,358		52,444,901	4
					128,238	128,238	5
69,628			2,979,240	1,526,596		4,505,836	6
					24,690	24,690	7
58,785			6,031,800	1,574,159		7,605,959	8
					7,917	7,917	9
499				20,145		20,145	10
9					448	448	11
5,315			59,057	228,251		287,308	12
5					-58,166	-58,166	13
86,458			5,670,180	1,943,358		7,613,538	14
9,879,567			331,345,004	380,821,333	1,899,288	714,065,625	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	LAKE COUNTY (1)	AD	COG	N/A	N/A	N/A
2	LAKE COGEN LIMITED (1)	OS	COG	102	108	97
3	LAKE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
4	DADE COUNTY (1)	OS	COG	29	48	27
5	DADE COUNTY (1)	AD	COG	N/A	N/A	N/A
6	ORANGE COGEN LIMITED (1)	OS	COG	74	104	65
7	ORANGE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
8	ORLANDO COGEN LIMITED (1)	OS	COG	72	95	81
9	ORLANDO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
10	PASCO COGEN LIMITED (1)	OS	COG	101	108	92
11	PASCO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
12	PASCO COUNTY (1)	OS	COG	22	25	19
13	PASCO COUNTY (1)	AD	COG	N/A	N/A	N/A
14	PCS PHOSPHATE (1)	OS	COG	N/A	13	5
	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	12/31/2005	End of 2005/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.
					42,363	42,363	1
434,400			30,415,663	18,511,814		48,927,477	2
					-16,887	-16,887	3
232,564			8,073,951	10,248,249		18,322,200	4
					-15,454	-15,454	5
350,367			26,015,982	9,565,026		35,581,008	6
					202,511	202,511	7
632,194			20,406,460	24,802,888		45,209,348	8
					-107,163	-107,163	9
464,963			37,748,694	13,677,285		51,425,979	10
					409,172	409,172	11
181,021			10,228,560	4,096,912		14,325,472	12
					84,690	84,690	13
39,324				3,199,175		3,199,175	14
9,879,567			331,345,004	380,821,333	1,899,288	714,065,625	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	PCS PHOSPHATE (1)	AD	COG	N/A	N/A	N/A
2	PINELLAS COUNTY (1)	OS	COG	52	64	43
3	PINELLAS COUNTY (1)	AD	COG	N/A	N/A	N/A
4	POLK POWER PARTNERS (1)	OS	COG	106	120	80
5	POLK POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
6	US AGRI-CHEMICALS CORPORATION (1)	OS	COG	3	13	4
7	US AGRI-CHEMICALS CORPORATION (1)	AD	COG	N/A	N/A	N/A
8	RIDGE GENERATING STATION (1)	OS	COG	33	41	27
9	RIDGE GENERATING STATION (1)	AD	COG	N/A	N/A	N/A
10	INTERCHANGE POWER:					
11	CHATTAHOOCHEE, CITY OF	OS				
12	CHATTAHOOCHEE, CITY OF	AD				
13	COBB ELECTRIC MEMBERSHIP CORP.	OS				
14	CAROLINA PWR. & LIGHT CO.	OS	FERC NO. 5			
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
-32					-709	-709	1
439,136			24,348,420	9,672,350		34,020,770	2
					207,578	207,578	3
440,773			43,764,641	10,744,513		54,509,154	4
					740,504	740,504	5
26,334			466,190	1,113,552		1,579,742	6
					18,185	18,185	7
157,650			9,594,608	5,812,074		15,406,682	8
					181,067	181,067	9
							10
			156,603			156,603	11
							12
407,937				28,799,653		28,799,653	13
				12,130		12,130	14
9,879,567			331,345,004	380,821,333	1,899,288	714,065,625	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	CAROLINA PWR. & LIGHT CO.	AD	FERC NO. 5			
2	CALPINE ENERGY SVCS., L.P.	OS	FERC NO. 170			
3	CARGILL-ALLIANT, LLC	OS				
4	CENTRAL POWER & LIME	OS				
5	DUKE ENERGY TRADING	OS				
6	FLORIDA POWER & LIGHT CO.	OS	FERC NO. 81			
7	FLORIDA POWER & LIGHT CO.	AD	FERC NO. 81			
8	FLORIDA MUNICIPAL POWER AGENCY	OS				
9	GEORGIA POWER	OS				
10	GEORGIA TRANSMISSION CORP	OS				
11	HOMESTEAD, CITY OF	OS	FERC NO. 82			
12	JACKSONVILLE ELECTRIC AUTHORITY	OS	FERC NO. 91			
13	JACKSONVILLE ELECTRIC AUTHORITY	AD	FERC NO. 91			
14	LAKELAND, CITY OF	OS	FERC NO. 92			
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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.
					358	358	1
67,044				5,754,842		5,754,842	2
6,342				638,172		638,172	3
63,564			1,357,930	2,034,048		3,391,978	4
1,473				140,629		140,629	5
69,038				6,274,421		6,274,421	6
					2,265	2,265	7
175				12,100		12,100	8
8,440				1,647,391		1,647,391	9
				22,668		22,668	10
100				6,500		6,500	11
				2,946,094		2,946,094	12
					7	7	13
1,515				159,650		159,650	14
9,879,567			331,345,004	380,821,333	1,899,288	714,065,625	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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	NEW HOPE POWER PARTNERSHIP	OS				
2	NEW SMYRNA BEACH, CITY OF	OS	FERC NO. 104			
3	OGLETHORPE POWER CORP	OS	FERC NO. 139			
4	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86			
5	PJM INTERCONNECTION, LLC	OS				
6	PJM INTERCONNECTION, LLC	AD				
7	REEDY CREEK UTILITIES	OS	FERC NO. 119			
8	RELIANT ENERGY SERVICES INC.	OS	FERC NO. 167			
9	RELIANT ENERGY SERVICES INC.	AD				
10	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128			
11	SEMINOLE ELECTRIC COOP INC.	AD	FERC NO. 128			
12	SOUTHERN COMPANY SERVICES INC.	OS	FERC NO. 111			
13	SOUTHERN COMPANY SERVICES INC.	AD	FERC NO. 70			
14	SOUTH CAROLINA ELECTRIC & GAS CO	OS				
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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)	
987				59,572		59,572	1
					-50,465	-50,465	2
225				6,225		6,225	3
13,935				1,028,300		1,028,300	4
1,263				69,359		69,359	5
					3,305	3,305	6
8,675			305,286	514,874	-55,286	764,874	7
312,343			1,595,800	45,327,342		46,923,142	8
					-5,885	-5,885	9
74,560				4,374,914		4,374,914	10
					4,516	4,516	11
3,811,826			55,446,192	83,645,668		139,091,860	12
					151,462	151,462	13
350				30,693		30,693	14
9,879,567			331,345,004	380,821,333	1,899,288	714,065,625	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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	TALLAHASSEE, CITY OF	OS	FERC NO. 122			
2	THE ENERGY AUTHORITY	OS	FERC NO. 175			
3	TAMPA ELECTRIC CO.	OS	FERC NO. 80			
4	TAMPA ELECTRIC CO.	AD	FERC NO. 80			
5	TENNESSEE VALLEY AUTHORITY	OS				
6						
7						
8	INADVERTENT INTERCHANGE (NET)					
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
1,615				573,804		573,804	1
349,713			3,600,000	42,293,476		45,893,476	2
413,535			7,917,204	18,908,191		26,825,395	3
					27	27	4
				4,555		4,555	5
							6
							7
-51							8
							9
							10
							11
							12
							13
							14
9,879,567			331,345,004	380,821,333	1,899,288	714,065,625	

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 COGENERATOR: ($12,938) ENERGY AND $141,176 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - BAY COUNTY: $10,940 ENERGY AND $13,750 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - CARGILL FERTILIZER: ($15,333) ENERGY AND $23,250 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - CITRUS WORLD: $448 ENERGY.

Schedule Page: 326 Line No.: 13 Column: l

OUT OF PERIOD ADJUSTMENT - JEFFERSON POWER: $300 ENERGY AND ($58,466) CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - LAKE COUNTY: $15,843 ENERGY AND $26,520 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - LAKE COGEN LIMITED: ($155,066) ENERGY AND $138,179 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - DADE COUNTY: $95,874 ENERGY AND ($111,328) CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - ORANGE COGEN LIMITED: $105,002 ENERGY AND $97,509 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - ORLANDO COGEN LIMITED: $111,562 ENERGY AND ($218,725) CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - PASCO COGEN LIMITED: $132,790 ENERGY AND $276,382 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - PASCO COUNTY: $36,850 ENERGY AND $47,840 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - PCS PHOSPHATE: ($709) ENERGY.

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

OUT OF PERIOD ADJUSTMENT - PINELLAS COUNTY: $93,698 ENERGY AND $113,880 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - POLK POWER PARTNERS: $121,992 ENERGY AND $618,512 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - US AGRI-CHEMICALS CORPORATION: $20,240 ENERGY AND ($2,055) CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - RIDGE GENERATING STATION: $22,106 ENERGY AND $158,961 CAPACITY.

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

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

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

OUT-OF-PERIOD ADJUSTMENT OF $358 TO ENERGY CHARGES FOR CAROLINA POWER & LIGHT

Schedule Page: 326.3 Line No.: 7 Column: l

OUT-OF-PERIOD ADJUSTMENT OF $2265 TO ENERGY CHARGES FOR FLORIDA POWER & LIGHT

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

OUT-OF-PERIOD ADJUSTMENT OF $7 TO ENERGY CHARGES FOR JACKSONVILLE ELECTRIC AUTHORITY

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

2005 OS PURCHASES FOR CITY OF NEW SYMRA BEACH INCLUDES ($50,465) CAPACITY CREDIT

Schedule Page: 326.4 Line No.: 6 Column: I

OUT-OF-PERIOD ADJUSTMENT OF $3305 TO ENERGY CHARGES FOR PJM

Schedule Page: 326.4 Line No.: 7 Column: I

2005 OS PURCHASES FOR REEDY CREEK UTILITIES INCLUDES ($55286) CAPACITY CREDIT

Schedule Page: 326.4 Line No.: 9 Column: I

OUT-OF-PERIOD ADJUSTMENT OF ($5885) TO ENERGY CHARGES FOR RELIANT ENERGY SERVICES

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

OUT-OF-PERIOD ADJUSTMENT OF $4516 TO ENERGY CHARGES FOR SEMINOLE ELECTRIC COOP

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

OUT-OF-PERIOD ADJUSTMENT OF $151,462 TO ENERGY CHARGES FOR SOUTHERN COMPANY SERVICES

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

OUT-OF-PERIOD ADJUSTMENT OF $27 TO ENERGY SERVICES FOR TAMPA ELECTRIC

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	Alabama Electric Coop	Various	Various	NF
2	American Electric Power Service	Various	Various	NF
3	Aquilla	Various	Various	AD
4	CIty of Alachua	Progress Energy Florida	City of Alachua	LFP
5	Calpine Energy Services	Various	Various	NF
6	Cargill-Alliant	Various	Various	NF
7	Central Power & Lime	Central Power & Lime	Florida Power & Light	LFP
8	Cinergy Services	Various	Various	NF
9	Cobb Electric Membership	Various	Various	NF
10	City of Homestead	Progress Energy Florida	City of Homestead	NF
11	City of Homestead	Progress Energy Florida	City of Homestead	SFP
12	City of Tallahassee	City of Tallahassee	City of Tallahassee	LFP
13	City of Tallahassee	Progress Energy Florida	City of Tallahassee	LFP
14	City of Tallahassee	Various	Various	NF
15	Conoco Inc.	Various	Various	NF
16	DTE Energy Trading	Various	Various	NF
17	Duke Energy Trading & Mkting	Various	Various	NF
	TOTAL			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Tariff 6	Various	Various				1
Tariff 6	Various	Various				2
Tariff 6	Various	Various				3
Tariff 6	Crystal River Sub	Gainesville Regional	1			4
Tariff 6	Various	Various		1,722	1,687	5
Tariff 6	Various	Various		36,945	36,144	6
Tariff 6	Brookridge Sub	FL Power & Light	137			7
Tariff 6	Various	Various		5,349	5,247	8
Tariff 6	Various	Various		31,228	30,601	9
Tariff 6	Various	FL Power & Light		133,424	130,685	10
Tariff 6	Various	FL Power & Light				11
Tariff 6	Jackson Bluff Sub	City of Tallahassee	11	28,298	27,699	12
Tariff 6	Progress Energy FL	City of Tallahassee	11	101,967	99,841	13
Tariff 6	Various	Various		254,579	249,375	14
Tariff 6	Various	Various				15
Tariff 6	Various	Various				16
Tariff 6	Various	Various		53	52	17
			855	**1,719,829**	**1,689,745**	

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.
2,570			2,570	1
220			220	2
				3
7,864			7,864	4
4,076			4,076	5
103,028			103,028	6
1,605,350			1,605,350	7
61,110			61,110	8
137,625			137,625	9
188,333			188,333	10
				11
152,261			152,261	12
163,202			163,202	13
539,748			539,748	14
				15
218			218	16
1,136			1,136	17
43,261,410	**0**	**0**	**43,261,410**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	Duke Power Company	Various	Various	NF
2	Dynegy Energy & Marketing	Various	Various	AD
3	Electric Clearinghouse, Inc	Various	Various	AD
4	Entergy-Koch Trading	Various	Various	NF
5	Florida Power & Light Co.	Progress Energy Florida	Florida Power & Light	LFP
6	Florida Power & Light Co.	Progress Energy Florida	Florida Power & Light	SFP
7	Florida Power & Light Co.	Various	Various	NF
8	Florida Municipal Power Authority	Various	Various	OS
9	Gainesville Regional Utilities	Progress Energy Florida	Gainesville Regional	LFP
10	Georgia Power Company	Progress Energy Florida	Georgia Power Co.	AD
11	Georgia Power Company	Progress Energy Florida	Georgia Power Co.	OLF
12	City of Kissimmee	Progress Energy Florida	Kissimmee Utility Authority	LFP
13	City of Lakeland	Various	Various	NF
14	City of Lakeland	Various	Various	AD
15	LG& E Energy Marketing	Various	Various	NF
16	Morgan Stanley Capital Group	Various	Various	NF
17	North Carolina Electric Membership Corp.	Various	Various	NF
	TOTAL			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Tariff 6	Various	Various				1
Tariff 6	Various	Various				2
Tariff 6	Various	Various				3
Tariff 6	Various	Various				4
Tariff 6	Progress Energy FL	FL Power & Light				5
Tariff 6	Progress Energy FL	FL Power & Light				6
Tariff 6	Various	Various		369	361	7
Tariff 6	Various	Various				8
Tariff 6	Crystal River Sub	Gainesville Regional	12			9
FERC No. 105	Intercession City Sb	Ga Power Company				10
FERC No. 105	Intercession City Sb	Ga Power Company	146			11
Tariff 6	Crystal River Sub	Kissimmee Utility	6	42,809	42,809	12
Tariff 6	Various	Various		414	405	13
Tariff 6	Various	Various				14
Tariff 6	Various	Various				15
Tariff 6	Various	Various				16
Tariff 6	Various	Various				17
			855	**1,719,829**	**1,689,745**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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.
				1
				2
				3
				4
				5
894,750			894,750	6
10,796			10,796	7
5,062,071			5,062,071	8
137,376			137,376	9
				10
592,344			592,344	11
68,141			68,141	12
2,512			2,512	13
				14
				15
				16
				17
43,261,410	**0**	**0**	**43,261,410**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	Oglethorpe Power Corp	Various	Various	NF
2	Orange Cogen LP	Orange Cogen LP	Tampa Electric Company	LFP
3	Orlando Utilities Commission	Progress Energy Florida	Orlando Utilities Commission	LFP
4	Orlando Utilities Commission	Various	Various	NF
5	Pennsylvania New Jersey Maryland	Various	Various	NF
6	Reedy Creek Improvement Dist.	Various	Various	NF
7	Reliant Energy Services	Reliant Energy Svcs	Florida Power & Light	LFP
8	Reliant Energy Services	Various	Various	AD
9	Seminole Electric Coop	Various	Various	OS
10	Seminole Electric Coop	Various	Various	NF
11	Seminole Electric Coop	Progress Energy Florida	Seminole Electric Coop	SFP
12	South Carolina Electric & Gas	Various	Various	NF
13	Southern Company of Florida	Various	Various	NF
14	Southern Company Services	Various	Various	NF
15	Southeastern Power Administration	Project	Preference Customers (18)	OS
16	Tampa Electric Company	Tampa Electric Company	Cities of Ft. Meade & Wachula	FNO
17	Tampa Electric Company	Progress Energy Florida	Tampa Electric Company	SFP
	TOTAL			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Tariff 6	Various	Various		5,558	5,497	1
Tariff 6	Orange Sub	Tampa Electric Co	23	74,618	74,618	2
Tariff 6	Crystal River Sub	Orlando Utilities Cm	13	102,452	102,452	3
Tariff 6	Various	Various				4
	Various	Various				5
Tariff 6	Various	Various		6,201	6,119	6
Tariff 6	Hudson Sub	FL Power & Light	474	334,499	327,605	7
Tariff 6	Various	Various		38,065	37,327	8
Tariff 6	Various	Various				9
Tariff 6	Various	Various		141,903	138,913	10
Tariff 6	Progress Energy FL	Seminole Electric Co	14	1,224	1,198	11
Tariff 6	Various	Various				12
Tariff 6	Various	Various				13
Tariff 6	Various	Various		320	313	14
65	Project	Preference Customers				15
Tariff 6	Tampa Electric Co.	Ft. Meade & Wachula				16
Tariff 6	Progress Energy FL	Tampa Electric Co.				17
			855	**1,719,829**	**1,689,745**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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.
21,447			21,447	1
318,363			318,363	2
161,568			161,568	3
28,918			28,918	4
32,605			32,605	5
16,412			16,412	6
6,293,166			6,293,166	7
394,579			394,579	8
19,976,852			19,976,852	9
260,424			260,424	10
223,525			223,525	11
117			117	12
				13
934			934	14
306,641			306,641	15
305,408			305,408	16
2,548,648			2,548,648	17
43,261,410	**0**	**0**	**43,261,410**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Tampa Electric Company	Various	Various	NF
2	Tennessee Valley Authority	Various	Various	NF
3	The Energy Authority	Gainesville Regional Utilities	Gainesville Regional Utililites	LFP
4	The Energy Authority	Various	Various	SFP
5	The Energy Authority	Various	Various	NF
6	City of New Smyrna Beach	Progress Energy Florida	Utilities Commission of NSB	LFP
7	City of New Smyrna Beach	Various	Various	SFP
8	City of New Smyrna Beach	Various	Various	NF
9	Reedy Creek Improvement District	Various	Various	OS
10	City of Winter Park	Progress Energy Florida	City of Winter Park	FNO
11	Progress Ventures	Various	Various	NF
12	Carolina Power & Light	Various	Various	NF
13	Florida Muncipal Power Authority	Various	Various	NF
14				
15				
16				
17				
	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	12/31/2005	End of 2005/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Tariff 6	Various	Various		10,940	10,693	1
Tariff 6	Various	Various				2
Tariff 6	Archer Sub	Gainesville Regional	2			3
Tariff 6	Various	Various				4
Tariff 6	Various	Various		112,220	109,944	5
Tariff 6	Crystal River Sub	New Smyrna Beach	5	36,061	36,061	6
Tariff 6	Various	Various				7
Tariff 6	Various	Various		216,075	211,619	8
Tariff 6	Various	Various				9
Tariff 6	Various	Various		604	584	10
Tariff 6	Various	Various		1,677	1,646	11
Tariff 6	Various	Various				12
Tariff 6	Various	Various		255	250	13
						14
						15
						16
						17
			855	1,719,829	1,689,745	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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.
35,503			35,503	1
10,119			10,119	2
47,834			47,834	3
				4
340,134			340,134	5
56,583			56,583	6
				7
440,647			440,647	8
875,240			875,240	9
826,611			826,611	10
3,518			3,518	11
138			138	12
745			745	13
				14
				15
				16
				17
43,261,410	**0**	**0**	**43,261,410**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	444,078
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Accounting Adjustments	1,572,267
7	Service Company Allocations	1,568,623
8	Fleet Transportation Clearing	1,258,024
9	Stores Burden Adjustment	551,000
10		
11		
12		
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45		
46	TOTAL	5,393,992

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			13,949,432		13,949,432
2	Steam Production Plant	56,094,792				56,094,792
3	Nuclear Production Plant	21,306,519	373,504			21,680,023
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	45,508,953				45,508,953
7	Transmission Plant	18,832,482				18,832,482
8	Distribution Plant	113,903,870				113,903,870
9	General Plant	14,031,822		13,860		14,045,682
10	Common Plant-Electric					
11	TOTAL	269,678,438	373,504	13,963,292		284,015,234

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	12/31/2005	End of 2005/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2005	2005/Q4

FOOTNOTE DATA

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

Depreciation rates do not include Nuclear Decommissioning. Nuclear Decommissioning accrued in 2004 was $38,650.92 and is included in the Account 403 - Depreciation Expense.

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

Per Instruction #3 for Section C, page 336 - All available information was adequately reported during the FERC Form 1 submission of 2001. Therefore, only accounts with changes to Estimated Avg Life, Net Salvage (Percent), Applied Depreciation Rates (Percent), Mortality Curve Type or Average Remaining Life would be listed. Depreciation rate details are included in the 2001 report, Pages 337, 337.1, and 337.2.

No accounts appear to have changes that would warrant listing in the 2005 FERC Form 1 submission.

Per Florida Public Service Commission Docket No. 020001-EI, Order No. PSC-02-0655-AS-EI, issued May 14, 2002, the Florida Public Service Commission approved a settlement which allowed Florida Power Corporation to reduce depreciation expense annually by $62.5M. This reduction is reflected in the totals Part A, column b.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	61,622,281		
4	Transmission	10,863,799		
5	Distribution	35,673,243		
6	Customer Accounts	25,544,705		
7	Customer Service and Informational	9,127,028		
8	Sales	1,321,104		
9	Administrative and General	48,724,833		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	192,876,993		
11	Maintenance			
12	Production	35,417,130		
13	Transmission	1,712,926		
14	Distribution	19,609,729		
15	Administrative and General	654,910		
16	TOTAL Maint. (Total of lines 12 thru 15)	57,394,695		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	97,039,411		
19	Transmission (Enter Total of lines 4 and 13)	12,576,725		
20	Distribution (Enter Total of lines 5 and 14)	55,282,972		
21	Customer Accounts (Transcribe from line 6)	25,544,705		
22	Customer Service and Informational (Transcribe from line 7)	9,127,028		
23	Sales (Transcribe from line 8)	1,321,104		
24	Administrative and General (Enter Total of lines 9 and 15)	49,379,743		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	250,271,688	23,367,291	273,638,979
26	Gas			
27	Operation			
28	Production-Manufactured Gas			
29	Production-Nat. Gas (Including Expl. and Dev.)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing			
32	Transmission			
33	Distribution			
34	Customer Accounts			
35	Customer Service and Informational			
36	Sales			
37	Administrative and General			
38	TOTAL Operation (Enter Total of lines 28 thru 37)			
39	Maintenance			
40	Production-Manufactured Gas			
41	Production-Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution			
46	Administrative and General			
47	TOTAL Maint. (Enter Total of lines 40 thru 46)			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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	Total Operation and Maintenance			
49	Production-Manufactured Gas (Enter Total of lines 28 and 40)			
50	Production-Natural Gas (Including Expl. and Dev.) (Total lines 29,			
51	Other Gas Supply (Enter Total of lines 30 and 42)			
52	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
53	Transmission (Lines 32 and 44)			
54	Distribution (Lines 33 and 45)			
55	Customer Accounts (Line 34)			
56	Customer Service and Informational (Line 35)			
57	Sales (Line 36)			
58	Administrative and General (Lines 37 and 46)			
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)			
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	250,271,688	23,367,291	273,638,979
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	69,320,502		69,320,502
66	Gas Plant			
67	Other (provide details in footnote):			
68	TOTAL Construction (Total of lines 65 thru 67)	69,320,502		69,320,502
69	Plant Removal (By Utility Departments)			
70	Electric Plant			
71	Gas Plant			
72	Other (provide details in footnote):			
73	TOTAL Plant Removal (Total of lines 70 thru 72)			
74	Other Accounts (Specify, provide details in footnote):			
75				
76				
77	Stores Exp Undistrib	6,578,630	500,042	7,078,672
78	Clearing Accounts	8,761,528		8,761,528
79	Misc Deferred Debits	6,532,717		6,532,717
80				
81	All Other Accounts	24,148,175	6,812	24,154,987
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	46,021,050	506,854	46,527,904
96	TOTAL SALARIES AND WAGES	365,613,240	23,874,145	389,487,385

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	910,658	MWH	15,442	430,126	MW Demand	924,487
2	Reactive Supply and Voltage	910,658	MWH	62,351	425,848	MW Demand	812,174
3	Regulation and Frequency Response				59,362	Mw Demand	70,884
4	Energy Imbalance				2,947	MW Demand	283,681
5	Operating Reserve - Spinning				604	MW Demand	26,054
6	Operating Reserve - Supplement				604	MW Demand	25,306
7	Other						
8	Total (Lines 1 thru 7)	1,821,316		77,793	919,491		2,142,586

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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:

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 (f)	Short-Term Firm Point-to-point Reservation (f)	Other Service (f)
1	January	13,005	24	800	9,633	26	746	2,300	300	
2	February	9,573	11	800	6,815	20	746	1,692	300	
3	March	9,557	3	2000	6,915	18	746	1,578	300	
4	Total for Quarter	32,135			23,363	64	2,238	5,570	900	
5	April	9,300	1	1600	6,516	19	728	1,737	300	
6	May	11,230	30	1700	7,633	21	728	2,548	300	
7	June	11,970	14	1800	8,204	112	728	2,776	150	
8	Total for Quarter	32,500			22,353	152	2,184	7,061	750	
9	July	12,981	27	1700	8,733	122	729	3,247	150	
10	August	13,212	16	1800	8,894	126	729	3,313	150	
11	September	12,594	19	1700	8,627	113	729	2,975	150	
12	Total for Quarter	38,787			26,254	361	2,187	9,535	450	
13	October	11,043	10	1700	7,709	107	729	2,348	150	
14	November	8,399	8	1600	5,982	82	539	1,646	150	
15	December	10,557	22	800	6,868	85	539	2,915	150	
16	Total for Quarter	29,999			20,559	274	1,807	6,909	450	
17	Total for Year to	133,421			92,529	851	8,416	29,075	2,550	

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ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	39,176,586
3	Steam	22,526,235			
4	Nuclear	5,828,926	23	Requirements Sales for Resale (See instruction 4, page 311.)	5,195,238
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	260,848
7	Other	8,874,301			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	37,229,462	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	135,773
10	Purchases	9,879,567	27	Total Energy Losses	2,370,668
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	47,139,113
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	1,719,829			
17	Delivered	1,689,745			
18	Net Transmission for Other (Line 16 minus line 17)	30,084			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	47,139,113			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	3,651,102	69,297	10,226	24	0800
30	February	3,132,616	26,774	7,399	11	0800
31	March	3,629,342	37,822	7,610	3	2000
32	April	3,293,797	10,709	7,012	1	1600
33	May	3,933,359	10,471	8,478	30	1700
34	June	4,230,337	15,337	8,927	14	1800
35	July	4,465,858	7,289	9,671	27	1700
36	August	4,954,276	1,240	9,686	16	1800
37	September	5,032,445	4,529	9,095	19	1700
38	October	3,985,803	18,178	8,301	10	1700
39	November	3,234,750	19,526	6,424	8	1600
40	December	3,595,428	39,676	7,772	22	0800
41	TOTAL	47,139,113	260,848			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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			494.40		
6	Net Peak Demand on Plant - MW (60 minutes)	1019			448		
7	Plant Hours Connected to Load	15219			21344		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1044			452		
10	When Limited by Condenser Water	993			444		
11	Average Number of Employees	76			78		
12	Net Generation, Exclusive of Plant Use - KWh	4302160000			1968359000		
13	Cost of Plant: Land and Land Rights	1869309			2046939		
14	Structures and Improvements	37336729			19238085		
15	Equipment Costs	228610157			124620876		
16	Asset Retirement Costs	315962			1929969		
17	Total Cost	268132157			147835869		
18	Cost per KW of Installed Capacity (line 17/5) Including	241.0393			299.0208		
19	Production Expenses: Oper, Supv, & Engr	19350			126609		
20	Fuel	235275769			107633956		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	345810			682901		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2310			2860		
26	Misc Steam (or Nuclear) Power Expenses	5665552			4908667		
27	Rents	0			0		
28	Allowances	6795759			3234451		
29	Maintenance Supervision and Engineering	1427109			1571660		
30	Maintenance of Structures	1118224			125251		
31	Maintenance of Boiler (or reactor) Plant	918298			2175303		
32	Maintenance of Electric Plant	162387			2798760		
33	Maintenance of Misc Steam (or Nuclear) Plant	5511357			4817464		
34	Total Production Expenses	257241925			128077882		
35	Expenses per Net KWh	0.0598			0.0651		
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	6486228	556466	0	3182572	115413	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	157116	1045	0	156639	1037	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	35.406	9.159	0.000	34.251	8.298	0.000
41	Average Cost of Fuel per Unit Burned	35.433	9.159	0.000	33.387	8.298	0.000
42	Average Cost of Fuel Burned per Million BTU	5.370	8.763	0.000	5.075	8.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.088	0.000	0.000	0.084	0.000
44	Average BTU per KWh Net Generation	0.000	10090.000	0.000	0.000	10448.000	0.000

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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
964.40	1478.50	890.50	5
870	1452	779	6
16245	16261	7671	7
0	0	0	8
874	1467	788	9
865	1437	769	10
173	223	487	11
5193072000	10693062000	5828926000	12
2512007	0	-150918	13
74864358	149104980	220626715	14
331998635	754469955	572847483	15
3683195	0	50846	16
413058195	903574935	793374126	17
428.3059	611.1430	890.9311	18
636675	744227	157350	19
147021614	269548053	30902753	20
0	0	3607835	21
2580300	4377837	11553683	22
0	0	0	23
0	0	0	24
389	1556	11700	25
5250706	6380467	34665696	26
0	0	0	27
8524124	11429207	0	28
401206	467238	13145056	29
89591	82012	897761	30
572372	5269509	18690742	31
227369	956002	2482936	32
8938827	6527074	2562762	33
174243173	305783182	118678274	34
0.0336	0.0286	0.0204	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Oil	Coal		Oil	Coal		Oil	Nuclear		36
BBL	Tons		BBL	Tons		BBL	MMBTU		37
25588	2115557	0	61120	4133139	0	312	60045673	0	38
137725	12346	0	137849	12232	0	137668	0	0	39
74.135	62.874	0.000	70.388	63.160	0.000	0.000	0.000	0.000	40
67.796	67.854	0.000	64.863	63.652	0.000	0.000	0.367	0.000	41
11.720	2.748	0.000	11.203	2.602	0.000	0.000	0.458	0.000	42
0.118	0.000	0.000	0.106	0.000	0.000	0.000	0.005	0.000	43
10102.000	0.000	0.000	9484.000	0.000	0.000	0.000	10302.000	0.000	44

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

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

Line No.	Item (a)	Plant Name: *Suwannee* (b)			Plant Name: *Bayboro* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1953			1973		
4	Year Last Unit was Installed	1956			1973		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	147.00			226.80		
6	Net Peak Demand on Plant - MW (60 minutes)	145			208		
7	Plant Hours Connected to Load	10588			1493		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	146			232		
10	When Limited by Condenser Water	143			184		
11	Average Number of Employees	37			4		
12	Net Generation, Exclusive of Plant Use - KWh	369582000			55145000		
13	Cost of Plant: Land and Land Rights	22059			1597635		
14	Structures and Improvements	5064160			1650590		
15	Equipment Costs	29140089			22635943		
16	Asset Retirement Costs	2366374			0		
17	Total Cost	36592682			25884168		
18	Cost per KW of Installed Capacity (line 17/5) Including	248.9298			114.1277		
19	Production Expenses: Oper, Supv, & Engr	14949			253601		
20	Fuel	32964406			9308110		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	296525			153751		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	972			0		
26	Misc Steam (or Nuclear) Power Expenses	3012958			427895		
27	Rents	0			0		
28	Allowances	1032150			0		
29	Maintenance Supervision and Engineering	-85999			0		
30	Maintenance of Structures	194737			14973		
31	Maintenance of Boiler (or reactor) Plant	374600			0		
32	Maintenance of Electric Plant	270487			-420		
33	Maintenance of Misc Steam (or Nuclear) Plant	1171087			326276		
34	Total Production Expenses	39246872			10484186		
35	Expenses per Net KWh	0.1062			0.1901		
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	665428	60244	0	131137	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	156142	1027	0	138167	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	51.477	13.751	0.000	80.581	0.000	0.000
41	Average Cost of Fuel per Unit Burned	47.791	13.751	0.000	70.706	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	7.287	13.393	0.000	12.184	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.170	0.000	0.168	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	12701.000	0.000	13800.000	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) 12/31/2005	Year/Period of Report End of 2005/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	1124	183	6
7459	15248	2752	7
0	0	0	8
762	1206	201	9
667	1041	164	10
20	30	2	11
364641000	827614000	103643000	12
2095203	746305	0	13
9644195	15754336	1471199	14
145203522	238583464	27471215	15
0	0	0	16
156942920	255084105	28942414	17
182.2333	194.6910	157.6384	18
2715768	3374634	483961	19
46105867	104747621	17422750	20
0	0	0	21
102170	132007	32729	22
0	0	0	23
0	0	0	24
0	0	0	25
1046012	1636503	221184	26
0	0	0	27
27774	14307	0	28
0	266741	0	29
145645	0	0	30
0	0	0	31
0	0	31166	32
196618	1325935	327053	33
50339854	111497748	18518843	34
0.1381	0.1347	0.1787	35

(d)			(e)			(f)			Line No.
Oil	Gas		Oil	Gas		Oil	Gas		36
BBL	MCF		BBL	MCF		BBL	MCF		37
268386	3399886	0	327641	8750376	0	72251	1036029	0	38
137768	1042	0	138167	1038	0	139150	1034	0	39
82.767	8.518	0.000	81.493	9.360	0.000	75.751	12.516	0.000	40
63.175	8.518	0.000	68.241	9.360	0.000	61.171	12.516	0.000	41
10.918	8.176	0.000	11.759	9.022	0.000	10.467	12.109	0.000	42
0.153	0.000	0.000	0.156	0.000	0.000	0.000	0.174	0.000	43
13973.000	0.000	0.000	13267.000	0.000	0.000	0.000	14406.000	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	12/31/2005	End of 2005/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			181.00		
6	Net Peak Demand on Plant - MW (60 minutes)	203			174		
7	Plant Hours Connected to Load	2898			682		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	219			194		
10	When Limited by Condenser Water	187			154		
11	Average Number of Employees	5			0		
12	Net Generation, Exclusive of Plant Use - KWh	80934000			32282000		
13	Cost of Plant: Land and Land Rights	0			824781		
14	Structures and Improvements	1074388			1328420		
15	Equipment Costs	23988825			21410369		
16	Asset Retirement Costs	0			586347		
17	Total Cost	25063213			24149917		
18	Cost per KW of Installed Capacity (line 17/5) Including	112.4920			133.4250		
19	Production Expenses: Oper, Supv, & Engr	414314			264860		
20	Fuel	11557194			5204208		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	28777			12940		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	368951			203749		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			6014		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	53751			36		
33	Maintenance of Misc Steam (or Nuclear) Plant	-183763			172200		
34	Total Production Expenses	12239224			5864007		
35	Expenses per Net KWh	0.1512			0.1816		
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	83790	749038	0	82255	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138460	1040	0	137651	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	83.218	8.810	0.000	77.009	0.000	0.000
41	Average Cost of Fuel per Unit Burned	58.348	8.810	0.000	58.661	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	10.033	8.471	0.000	10.147	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.157	0.000	0.000	0.149	0.000	0.000
44	Average BTU per KWh Net Generation	15646.000	0.000	0.000	14731.000	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	12/31/2005	End of 2005/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
67.60	153.40	278.20	5
58	128	215	6
872	2258	4698	7
0	0	0	8
64	134	223	9
52	122	207	10
0	2	10	11
20105000	56169000	884459000	12
67555	184271	0	13
405755	718306	10553415	14
8196091	17049419	80948757	15
0	0	0	16
8669401	17951996	91502172	17
128.2456	117.0274	328.9079	18
375475	268978	2188335	19
2656039	7486505	57727309	20
0	0	0	21
4286	157170	45805	22
0	0	0	23
0	0	0	24
132289	191461	640600	25
0	0	0	26
0	0	0	27
0	0	635	28
10913	0	0	29
0	0	0	30
0	0	0	31
0	70216	367526	32
46883	196458	994889	33
3225885	8370788	61965099	34
0.1605	0.1490	0.0701	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Oil	Gas		Oil	Gas		Gas			36
BBL	MCF		BBL	MCF		MCF			37
11177	266965	0	133	922915	0	6797713	0	0	38
137687	1036	0	137308	1038	0	1038	0	0	39
76.390	7.406	0.000	0.000	8.100	0.000	8.492	0.000	0.000	40
59.600	7.406	0.000	35.120	8.100	0.000	8.492	0.000	0.000	41
10.306	7.151	0.000	6.090	7.803	0.000	8.180	0.000	0.000	42
0.175	0.000	0.000	0.000	0.133	0.000	0.065	0.000	0.000	43
16965.000	0.000	0.000	0.000	17070.000	0.000	7979.000	0.000	0.000	44

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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)	19.30			43.00		
6	Net Peak Demand on Plant - MW (60 minutes)	15			38		
7	Plant Hours Connected to Load	144			8053		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	16			41		
10	When Limited by Condenser Water	13			35		
11	Average Number of Employees	0			11		
12	Net Generation, Exclusive of Plant Use - KWh	1475000			376181000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	88646			6499783		
15	Equipment Costs	3035059			35036114		
16	Asset Retirement Costs	0			0		
17	Total Cost	3123705			41535897		
18	Cost per KW of Installed Capacity (line 17/5) Including	161.8500			965.9511		
19	Production Expenses: Oper, Supv, & Engr	28522			1114854		
20	Fuel	294292			25330454		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	13022			26972		
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	10833			252330		
27	Rents	0			0		
28	Allowances	0			234		
29	Maintenance Supervision and Engineering	0			104496		
30	Maintenance of Structures	16246			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	687			501544		
33	Maintenance of Misc Steam (or Nuclear) Plant	5509			828772		
34	Total Production Expenses	369111			28159656		
35	Expenses per Net KWh	0.2502			0.0749		
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	4701	0	0	3565734	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	137772	0	0	1038	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	81.101	0.000	0.000	7.072	0.000	0.000
41	Average Cost of Fuel per Unit Burned	60.060	0.000	0.000	7.072	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	10.380	0.000	0.000	6.812	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.191	0.000	0.000	0.067	0.000	0.000
44	Average BTU per KWh Net Generation	18442.000	0.000	0.000	9840.000	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) 12/31/2005	Year/Period of Report End of 2005/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			3
2005			4
1734.50	0.00	0.00	5
1593	0	0	6
15852	0	0	7
0	0	0	8
1687	0	0	9
1499	0	0	10
48	0	0	11
6071653000	0	0	12
13373240	0	0	13
66270644	0	0	14
719266586	0	0	15
0	0	0	16
798910470	0	0	17
460.5999	0.0000	0.0000	18
2637065	0	0	19
377565659	0	0	20
0	0	0	21
3636292	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
1787547	0	0	26
0	0	0	27
2980	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
802791	0	0	32
5102053	0	0	33
391534387	0	0	34
0.0645	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
Oil	Gas								37
BBL	MCF								37
2615	42355861	0	0	0	0	0	0	0	38
133342	1033	0	0	0	0	0	0	0	39
96.796	8.875	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
41.034	8.875	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
7.327	8.594	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.062	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	7207.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	500KV LINES	OVERHEAD						
2	CENTRAL FLORIDA	KATHLEEN	500.00	500.00	ST	44.22		1
3	CRYSTAL RIVER SUB	BROOKRIDGE	500.00	500.00	ST	34.40		1
4	BROOKRIDGE	LAKE TARPON	500.00	500.00	ST	37.63		1
5	CRYSTAL RIVER SUB	CENTRAL FLORIDA	500.00	500.00	ST	52.91		1
6								
7	230 KV LINES	UNDERGROUND						
8	BARTOW PLANT	NORTHEAST	230.00	230.00	HPOF	3.91		1
9	BARTOW PLANT	NORTHEAST	230.00	230.00	HPOF	3.98		1
10								
11	230 KV LINES	OVERHEAD						
12	AVON PARK	FORT MEADE	230.00	230.00	ST	4.30		1
13					CP	2.01		
14					WH	19.86		
15					WP	0.94		
16					SP		1.22	
17	AVON PARK	FISHEATING CREEK	230.00	230.00	SP	9.02		1
18					CP	17.05		
19					WH	3.29		
20	ANCLOTE PLANT	LARGO	230.00	230.00	SH	15.29		1
21					SP	8.54		
22	ANCLOTE PLANT	EAST CLEARWATER	230.00	230.00	SH		15.30	1
23	ANCLOTE PLANT	SEVEN SPRINGS	230.00	230.00	SP	7.71		1
24	ALTAMONTE	WOODSMERE	230.00	230.00	WP	0.10		1
25					ST		0.56	
26					WH	10.20		
27					SP	0.82		
28	BARCOLA	LAKELAND WEST	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	77.82	72.50	1
32	CRYSTAL RIVER	ANDERSON	230.00	230.00	ST	53.36	39.59	1
33	CRYSTAL RIVER	FT. WHITE	230.00	230.00	WH	73.31		1
34	CENTRAL FLORIDA	SILVER SPRINGS	230.00	230.00	ST	27.49	5.51	1
35	CFS 1	SORRENTO	230.00	230.00	CP	14.65		1
36					TOTAL	4,219.07	537.74	74

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
2156 KCM ACSR	2,099,487	20,117,954	22,217,441					2
2335 KCM ACSR	12,767	12,202,249	12,215,016					3
2335 KCM ACSR								4
2335 KCM ACSR	9,840	8,756,291	8,766,131					5
								6
								7
2500 KCM CU		2,088,494	2,088,494					8
2500 KCM CU	251,470	2,109,689	2,361,159					9
								10
								11
1081 KCM ACSR	85,476	3,416,959	3,502,435					12
954 KCM ACSR								13
954 KCM ACSR								14
954 KCM ACSR								15
954 KCM ACSR								16
1590 KCM ACSR	481,954	8,826,523	9,308,477					17
1590 KCM ACSR								18
1590 KCM ACSR								19
1590 KCM ACSR	389,829	5,616,793	6,006,622					20
1590 KCM ACSR								21
1590 KCM ACSR		635,748	635,748					22
2335 KCM ACAR	1,145,863	1,387,207	2,533,070					23
1590 KCM ACSR	43,803	1,550,285	1,594,088					24
1590 KCM ACSR								25
1590 KCM ACSR								26
1590 KCM ACSR								27
1590 KCM ACSR	133,007	2,576,890	2,709,897					28
1622 KCM		3,427,956	3,427,956					29
1590 KCM ACSR		110,272	110,272					30
1590 KCM ACSR	1,266,890	10,762,869	12,029,759					31
1590 KCM ACSR	774,675	6,750,321	7,524,996					32
954 KCM ACSR	219,431	5,397,859	5,617,290					33
1590 KCM ACSR	439,516	3,220,391	3,659,907					34
1590 KCM ACSR	1,621,137	10,713,298	12,334,435					35
	61,704,424	569,648,821	631,353,245	405,758	7,238,079		7,643,837	36

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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	46.61	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	CC-248	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	0.12		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	4,219.07	537.74	74

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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)	
1590 KCM ACSR								1
1590 KCM ACSR	1,128,343	5,903,286	7,031,629					2
954 KCM ACSR	439,029	4,537,970	4,976,999					3
954 KCM ACSR								4
954 KCM ACSR	176,825	5,706,281	5,883,106					5
954 KCM ACSR								6
954 KCM ACSR								7
1590 KCM ACSR	66,391	139,498	205,889					8
1590 KCM ACSR	271,527	2,250,763	2,522,290					9
1590 KCM ACSR								10
1590 KCM ACSR								11
1590/1431 KCM								12
1590 KCM ACSR	557,537	2,493,378	3,050,915					13
1590 KCM ACSR								14
1590 KCM ACSR								15
954 KCM ACSR	129,493	2,918,991	3,048,484					16
954 KCM ACSR								17
1590 KCM ACSR								18
1431 KCM ACSR								19
1590 KCM ACSR								20
954 KCM ACSR	195,181	1,614,155	1,809,336					21
954 KCM ACSR								22
1590 KCM ACSR	1,073,673	10,865,156	11,938,829					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	858,026	860,536					30
1590 KCM ACSR								31
954 KCM ACSR	63,923	3,216,807	3,280,730					32
954 KCM ACSR								33
954 KCM ACSR								34
1081 KCM ACAR	55,284	1,294,309	1,349,593					35
	61,704,424	569,648,821	631,353,245	405,758	7,238,079		7,643,837	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	12/31/2005	End of 2005/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					WH	16.80		
2	TIGER BAY	TECO	230.00	230.00	CP	0.10		1
3					ST	5.86		
4					WH	1.38		
5	HINES ENERGY	FORT MEADE	230.00	230.00	SP	6.45		1
6	HINES ENERGY	BARCOLA	230.00	230.00	SP	3.09		1
7	HINES ENERGY	BARCOLA (2ND CIRCUIT)	230.00	230.00	SP	3.09		1
8	HINES ENERGY	TIGER BAY	230.00	230.00	SP	0.64	3.51	
9	HINES PLANT	HINES	230.00	230.00	SP	1.64		
10	OLD SUB NORTH	NEW SUB NORTH	230.00	230.00	SP	0.22		1
11	KATHLEEN	LAKELAND WEST	230.00	230.00	WH	14.50		1
12					CP	1.31		
13	KATHLEEN	ZEPHYRHILLS NORTH	230.00	230.00	WH	0.83		1
14					CP	8.70		
15					WP	1.35		
16	LARGO	PASADENA	230.00	230.00	ST		1.61	1
17					SP	13.13		
18	LAKE TARPON	CURLEW	230.00	230.00	ST	4.32		1
19	LAKE TARPON	HIGGINS	230.00	230.00	CP	2.57		1
20					SP	3.02		
21	CURLEW	CLEARWATER	230.00	230.00	SP	14.49		1
22					CP	2.90		
23	CC 248	SEVEN SPRINGS	230.00	230.00	ST	2.90		1
24	LAKE TARPON	TECO EXIST	230.00	230.00	ST	0.68		1
25					SP	0.81		
26	NORTHEAST	CUR CC 301	230.00	230.00	ST	16.95	12.78	1
27	NORTHEAST	40TH ST.	230.00	230.00	CP	0.16		1
28					SP	8.16		
29	NORTH LONGWOOD	PIEDMONT	230.00	230.00	SP	0.31	4.04	1
30					WH	6.16		
31	NORTH LONGWOOD	FP&L CO TIE	230.00	230.00	SP	4.04		1
32					WH	2.77		
33	NORTH LONGWOOD	RIO PINAR	230.00	230.00	SP	0.58	3.94	1
34					CP	0.21		
35					AT	10.91		
36					TOTAL	4,219.07	537.74	74

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1081 KCM ACAR								1
1590/1081 KCM	2,353	378,382	380,735					2
1081 KCM ACAR								3
1081/954 KCM								4
954 KCM ACSR		2,805,003	2,805,003					5
954 KCM ACSR		1,531,577	1,531,577					6
954 KCM ACSR		1,412,301	1,412,301					7
954 KCM ACSR		1,455,041	1,455,041					8
954 KCM ACSR		182,380	182,380					9
2335 KCM ACAR		194,088	194,088					10
1590 KCM ACSR	485,915	2,921,127	3,407,042					11
1590 KCM ACSR								12
1590 KCM ACSR	275,097	3,010,806	3,285,903					13
1590 KCM ACSR								14
1590 KCM ACSR								15
1590 KCM ACSR	152,473	2,700,828	2,853,301					16
1590 KCM ACSR								17
1590 KCM ACSR		955,417	955,417					18
1590 KCM ACSR	15,699	1,499,798	1,515,497					19
1590 KCM ACSR								20
1590 KCM ACSR	412,563	8,575,830	8,988,393					21
1590 KCM ACSR								22
1590 KCM ACSR	189,338	694,404	883,742					23
1590 KCM ACSR		197,855	197,855					24
1590 KCM ACSR								25
1590 KCM ACSR	1,517,258	2,482,574	3,999,832					26
1590 KCM ACSR	288,076	1,369,702	1,657,778					27
1081 KCM ACAR								28
954 KCM ACSR	16,834	512,535	529,369					29
954 KCM ACSR								30
954 KCM ACSR	207,841	1,123,050	1,330,891					31
954 KCM ACSR								32
1590 KCM ACSR	420,736	1,976,421	2,397,157					33
954 KCM ACSR								34
954 KCM ACSR								35
	61,704,424	569,648,821	631,353,245	405,758	7,238,079		7,643,837	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	12/31/2005	End of 2005/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)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	NEWBERRY	WILCOX	230.00	230.00	SP	19.33		1
2	NORTHEAST	PINELLAS	230.00	230.00	CP	1.90		1
3	PIEDMONT	SORRENTO	230.00	230.00	SP	4.24		1
4					CP	6.45		
5					WH	4.79		
6	PIEDMONT	WOODSMERE	230.00	230.00	WH	6.72		1
7	PORT ST. JOE	GULF POWER	230.00	230.00	ST	33.99		1
8	RIO PINAR	OUC TIE	230.00	230.00	SP	0.52		1
9					AT	2.19		
10	CFO 89	DELAND WEST	230.00	230.00	SL	39.93		1
11					SH	0.92		
12					SP	1.57		
13	SUWANNEE	FORT WHITE	230.00	230.00	ST	38.08		1
14	SLX 1	OUC SO WD	230.00	230.00	CP	2.40		1
15					WP	2.22		
16	SUWANNEE	PERRY	230.00	230.00	ST	28.61		1
17	SUWANNEE PEAKERS	SUWANNEE	230.00	230.00	WH	0.63		1
18	SUWANNEE	GEORGIA	230.00	230.00	ST	18.36		1
19	TIGER BAY	FORT MEADE 2	230.00	230.00	SP	0.44	1.78	1
20	ULMERTON	LARGO	230.00	230.00	ST	5.05		1
21	VANDOLAH	WHIDDEN	230.00	230.00	SP	14.40		1
22	WINDERMERE	INTERCESSION CITY	230.00	230.00	WH	9.80		1
23					CP	0.27		
24					SP	5.33	4.85	
25	WINDERMERE	WOODSMERE	230.00	230.00	WH	4.68		1
26					ST	1.82		
27	WEST LAKE WALES	INTERCESSION CITY	230.00	230.00	WH	29.34		1
28					SP	0.72		
29	WEST LAKE WALES	FP&L CO	230.00	230.00	AT	58.48		1
30	WEST LAKE WALES	TECO	230.00	230.00	AT	2.29		1
31	WLIC-75A	DUNDEE	230.00	230.00	SP	0.07		1
32	WOODSMERE	WIW 45	230.00	230.00	ST		0.92	1
33	WINDERMERE	OUC TIE	230.00	230.00	WH	1.31		1
34								
35								
36					TOTAL	4,219.07	537.74	74

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1590 KCM ACSR	661,118	5,775,605	6,436,723					1
954 KCM ACSR		4,498	4,498					2
1590 KCM ACSR	574,273	4,917,855	5,492,128					3
1590 KCM ACSR								4
1590 KCM ACSR								5
954 KCM ACSR	15,605	491,284	506,889					6
795 KCM ACSR	71,747	2,297,172	2,368,919					7
954 KCM ACSR	100,034	704,855	804,889					8
954 KCM ACSR								9
1590 KCM ACSR	54,890	6,226,547	6,281,437					10
1590 KCM ACSR								11
1590 KCM ACSR								12
954 KCM ACSR	196,750	2,362,830	2,559,580					13
954 KCM ACSR	121,530	1,160,369	1,281,899					14
954 KCM ACSR								15
795 KCM ACSR	151,754	1,320,102	1,471,856					16
795 KCM ACSR		8,063	8,063					17
954 KCM ACSR	104,190	1,110,240	1,214,430					18
954 KCM ACSR		747,871	747,871					19
1590 KCM ACSR	601,048	578,997	1,180,045					20
1622ACSS TW		14,093,015	14,093,015					21
954 KCM ACSR	135,968	2,654,588	2,790,556					22
954 KCM								23
1622ACSS TW								24
1590 KCM ACSR	19,739	876,994	896,733					25
1590 KCM ACSR								26
954/1081 KCM	174,960	2,279,762	2,454,722					27
1622ACSS TW								28
954 KCM ACSR	595,327	4,760,766	5,356,093					29
954 KCM ACSR	17,342	232,082	249,424					30
1622ACSS TW		399,672	399,672					31
954 KCM ACSR		4,479	4,479					32
954 KCM ACSR		431,758	431,758					33
								34
								35
	61,704,424	569,648,821	631,353,245	405,758	7,238,079		7,643,837	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	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	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								
2	OTHER TRANS. LINES	OVERHEAD 115 & 69				2,780.12	304.00	
3	OTHER TRANS. LINES	UNDERGROUND 115				47.29		
4								
5	Total Overhead Transmission	Line Expenses				4,219.07	537.74	74
6		(230, 115, 69 Kv)						
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					TOTAL	4,219.07	537.74	74

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/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.
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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
	40,450,993	312,593,259	353,044,252					2
	88,132	11,739,339	11,827,471					3
								4
	61,704,424	569,648,821	631,353,245					5
				405,758	7,238,079		7,643,837	6
								7
								8
								9
								10
								11
								12
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								30
								31
								32
								33
								34
								35
	61,704,424	569,648,821	631,353,245	405,758	7,238,079		7,643,837	36

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

2005 transmission pole mile statistics have been updated to reflect current and prior year minor additions.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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	VANDOLAH	WHIDDEN	14.40	SP	6.00	1	1
2	GROVELAND	GSH-54	3.96	CP	10.00	1	1
3	WLIC-75A	DUNDEE	0.07	SP	6.00	1	1
4	BWSX-23	SPRING HILL 3	3.33	CP	10.00	1	1
5	AF2-95-53	LAKE BRANCH	4.18	CP	10.00	1	1
6	ATL-299	ATL-379	6.20	CP	10.00	1	1
7	NEW PORT RICHEY	WREC POLE	0.02	CP	10.00	1	1
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	TOTAL		32.16		62.00	7	7

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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	v	230		10,783,975	3,309,040		14,093,015	1
795	AAC	v	69		2,194,183	708,943		2,903,126	2
1622	ACSS TW	v	230		341,763	31,341	26,568	399,672	3
795	AAC	v	69		1,651,118	456,879	10,734	2,118,731	4
410	ACSR	v	69		666,770	394,458	2,536	1,063,764	5
795	AAC	v	69		2,551,650	865,586		3,417,236	6
795	AAC	v	69			47,496	35,456	82,952	7
									8
									9
									10
									11
									12
									13
									14
									15
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									42
									43
					18,189,459	5,813,743	75,294	24,078,496	44

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	32ND STREET - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	40TH STREET - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
3	51ST STREET - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
4	ALDERMAN - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
5	ANCLOTE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
6	BAYBORO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	BAYVIEW - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	BAYWAY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
9	BELLEAIR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	BROOKER CREEK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	BROOKSVILLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	12.00
12	BROOKSVILLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	7.00
13	BROOKSVILLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	13.00
14	BROOKSVILLE ROCK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	2.00	
15	BUSHNELL - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	CAMPS SECTION 7 MINE-SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
17	CENTER HILL - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	CENTRAL PLAZA - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
19	CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	CONSOLIDATED ROCK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
21	CROSS BAYOU - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	CROSSROADS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	CURLEW - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	DENHAM - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	DISSTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
26	DISSTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
27	DUNEDIN - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	14.00
29	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	240.00	120.00	
30	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
31	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	ELFERS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
33	FLORAL CITY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	FLORA-MAR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
35	FLORIDA ROCK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	66.00	3.00	
36	G.E. PINELLAS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	GATEWAY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
38	HAMMOCK - SUNCOAST FLORDAI REGION	DIST - UNATTENDED	115.00	4.00	
39	HAMMOCK - SUNCOAST FLORDAI REGION	DIST - UNATTENDED	67.00	4.00	
40	HIGHLANDS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2					1
60	2					2
80	2					3
90	3					4
100	2					5
60	2					6
100	2					7
40	1					8
80	2					9
60	2					10
150	1					11
100	1					12
60	2					13
9	1	1				14
13	1					15
19	2	1				16
13	1	1				17
60	2					18
120	4					19
2	1	1				20
150	3					21
80	2					22
90	3					23
90	3					24
150	1					25
80	2					26
60	3					27
200	1					28
200	1					29
250	1					30
150	3					31
100	2					32
13	1					33
100	2					34
12	2	2				35
29	2					36
90	3					37
20	1					38
19	2					39
80	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	KENNETH CITY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
3	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
4	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	5.00
5	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	MAXIMO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	NEW PORT RICHEY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	NORTHEAST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	15.00
9	NORTHEAST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
10	OAKHURST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	PALM HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
12	PALM HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	PASADENA - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
14	PASADENA - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
15	PILSBURY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
16	PINELLAS WELL FIELD - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	66.00	3.00	
17	PORT RICHEY WEST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
18	SAFETY HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
19	SEMINOLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
20	SEMINOLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	SEVEN SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
22	SEVEN SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
23	SIXTEENTH ST. - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	STARKEY ROAD - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	TANGERINE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	8.00
26	TARPON SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	
27	TARPON SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
28	TAYLOR AVE. - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	TRI-CITY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
30	TRILBY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
31	ULMERTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	14.00
32	ULMERTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
33	ULMERTON WEST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	VINOY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
35	WALSINGHAM - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	ZEPHYRHILLS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	ZEPHYRHILLS NORTH - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
38	ZEPHYRHILLS NORTH - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
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	12/31/2005	End of 2005/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
200	1					2
200	1					3
200	1					4
100	2					5
150	3					6
60	2					7
400	2					8
100	2					9
90	3					10
250	1					11
60	2					12
250	1					13
80	2					14
100	2					15
5	1	1				16
90	3					17
80	2					18
250	1					19
100	2					20
60	2					21
750	3					22
80	2					23
80	2					24
60	2					25
150	1					26
100	2					27
80	2					28
60	2					29
9	1	1				30
450	2					31
100	2					32
80	2					33
100	2					34
100	2					35
60	2					36
250	1					37
60	2					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	12/31/2005	End of 2005/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	ALACHUA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	APALACHICOLA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	ARCHER - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
4	ARCHER - NORTH FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
5	BEACON HILL - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	CARRABELLE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	CARRABELLE BEACH - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
8	CRAWFORDVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
9	CRAWFORDVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
10	CROSS CITY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	EAST POINT - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	FOLEY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	FORT WHITE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
14	FORT WHITE - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	4.00
15	FORT WHITE - NORTH FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
16	G.E. ALACHUA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	GAINESVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
18	GEORGIA PACIFIC - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	HIGH SPRINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	HIGH SPRINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	7.00	
21	HULL ROAD - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	INDIAN PASS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	JASPER - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
24	JASPER - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	JENNINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
26	LURAVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	MADISON - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
28	MONTICELLO - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	NEWBERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
30	NEWBERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
31	O'BRIEN - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	OCCIDENTAL #1 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
33	OCCIDENTAL #1 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	
34	OCCIDENTAL #2 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
35	OCCIDENTAL #3 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
36	OCCIDENTAL SWIFT CREEK#1-NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
37	OCCIDENTAL SWIFT CREEK#2-NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	
38	OCCIDENTAL SWIFT CREEK#2-NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
39	OCHLOCKONEE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	PERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00

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	12/31/2005	End of 2005/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.
13	1	1				1
13	1	1				2
150	1					3
16	2	2				4
13	1	1				5
13	1	1				6
2	1	1				7
100	1					8
13	1	1				9
13	1	1				10
13	1	1				11
40	2					12
100	1					13
75	1					14
6	1	1				15
20	1					16
30	1					17
10	1	1				18
9	1					19
13	1	1				20
19	2					21
5	1	1				22
60	1					23
13	1	1				24
2	1	1				25
9	1	1				26
40	2					27
40	2					28
100	1					29
13	1	1				30
6	1	1				31
13	1					32
25	1					33
40	2					34
13	1					35
60	3					36
20	1					37
30	1					38
9	1	1				39
250	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	PERRY NORTH - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	PORT ST. JOE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
4	PORT ST. JOE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	PORT ST. JOE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
6	RIVER JUNCTION - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	SHAMROCK - NORTH FLORIDA REGION	DIST - UNATTENDED	12.00	4.00	
8	SOPCHOPPY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	ST. GEORGE ISLAND - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	ST. MARKS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	SUTTERS CREEK - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	TRENTON - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	UNIVERSITY OF FLORIDA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	23.00	
14	WAUKEENAH - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
15	WHITE SPRINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
16	WILLISTON - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	WILLISTON TOWN - NORTH FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
18					
19	ADAMS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	ALAFAYA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	ALTAMONTE SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
22	ALTAMONTE SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23	APOPKA SOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	BARBERVILLE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	BAY RIDGE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	BELLEVIEW - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	BEVERLY HILLS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
28	CASSADAGA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
29	CASSELBERRY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
30	CIRCLE SQUARE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	CITRUS HILL - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
32	CLARCONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	CLERMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	COLEMAN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	CRYSTAL RIVER NORTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
36	CRYSTAL RIVER SOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
37	DELAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
38	DELAND EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
39	DELTONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	
40	DELTONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
40	2					1
20	1					2
100	1					3
20	1					4
200	2					5
19	1	1				6
2	1	1				7
9	1	1				8
20	1					9
13	1	1				10
19	2					11
13	1	1				12
90	3					13
9	1					14
2	1	1				15
13	1	1				16
9	1					17
						18
20	1					19
60	2					20
200	1					21
100	2					22
90	3					23
40	2					24
40	2					25
40	2					26
60	2					27
60	2					28
120	3					29
19	2					30
20	1					31
90	3					32
60	2					33
29	2					34
19	1	1				35
9	1	1				36
100	2					37
90	3					38
75	1					39
120	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	DELTONA EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
2	DOUGLAS AVENUE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	DUNNELLON TOWN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	EAGLENEST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	EATONVILLE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	ECON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
7	EUSTIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	EUSTIS SOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
9	FERN PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
10	GROVELAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	116.00	
12	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
13	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
14	HOMOSASSA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
15	HOWEY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	INGLIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	67.00	
17	INGLIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	INVERNESS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	7.00
19	INVERNESS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	KELLER ROAD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	KELLY PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	LADY LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23	LAKE ALOMA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	LAKE EMMA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
25	LAKE HELEN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
26	LAKE WEIR - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	LEBANON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	12.00	
28	LIBSON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
29	LOCKHART - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
30	LOCKWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
32	MAITLAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	MARICAMP - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	MARTIN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	MCINTOSH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	MINNEOLA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
37	MONTEVERDE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
38	MOUNT DORA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
39	MYRTLE LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
40	NORTH LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
60	2					1
60	2					2
40	2					3
19	2					4
90	3					5
100	2					6
60	2					7
63	2					8
30	1					9
19	2					10
250	1					11
250	1					12
19	2					13
20	1					14
13	1	1				15
100	1					16
9	1					17
160	2					18
60	2					19
60	2					20
9	1					21
29	2					22
100	2					23
100	2					24
55	2					25
19	2					26
5	1	1				27
40	2					28
100	2					29
30	1					30
40	2					31
90	3					32
19	2					33
20	1					34
9	1					35
20	1					36
40	2					37
40	2					38
100	2					39
250	1					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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	NORTH LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
2	OCOEE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	OKAHUMPKA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	ORANGE BLOSSOM - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	ORANGE CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	115.00	14.00
6	ORANGE CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
7	OVIEDO - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	PIEDMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
9	PIEDMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	PLYMOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	PLYMOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
12	RAINBOW SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	REDDICK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	SANTOS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
15	SILVER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
16	SILVER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	SILVER SPRINGS SHORES-NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	SPRING LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	TROPIC TERRACE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
20	TURNER PLANT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	7.00
21	TURNER PLANT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	TWIN COUNTY RANCH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	110.00	13.00	
23	TWIN COUNTY RANCH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
24	UNIV OF CENTRAL FL - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	UNIV OF CNTL FL NORTH-NORTH CNTL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	UMATILLA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	WEIRSDALE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
28	WEKIVA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
29	WELCH ROAD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
30	WEST CHAPMAN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	WILDWOOD CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
32	WINTER GARDEN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	WINTER GARDEN CITRUS-NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	WINTER GARDEN CITRUS#2-NORTH CENTRAL FL REGION	DIST - UNATTENDED	12.00		
35	WINTER GARDEN CITRUS#2-NORTH CENTRAL FL REGION	DIST - UNATTENDED	12.00		
36	WINTER PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	WINTER PARK EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
38	WINTER PARK EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
39	WINTER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
40	WINTER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
100	2					1
90	3					2
40	2					3
40	2					4
250	1					5
60	2					6
90	3					7
250	1					8
100	2					9
13	1	1				10
9	1					11
19	2					12
22	2					13
13	1					14
250	1					15
20	1					16
40	2					17
90	3					18
40	2					19
160	2					20
40	2					21
13	1	1				22
9	1					23
60	2					24
60	2					25
40	2					26
19	2					27
100	2					28
100	2					29
60	2					30
25	1					31
60	2					32
9	1	1				33
1	1					34
5	4					35
120	4					36
500	2					37
100	2					38
250	1					39
90	3					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	WOODSMERE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
2	WOODSMERE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	ZELLWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	ZUBER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5					
6	AGRICOLA #4 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	ARBUCKLE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
9	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	67.00	12.00
10	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	AVON PARK NORTH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
12	BABSON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	BARNUM CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	BAY HILL - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
15	BITHLO - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	BOGGY MARSH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	BONNET CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	CABBAGE ISLAND - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	CANOE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	4.00
20	CELEBRATION - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	CENTRAL PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	CHAMPIONS GATE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
23	CITRUSVILLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	CLEAR SPRINGS EAST - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
25	CONWAY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	COUNTRY OAKS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	CROOKED LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
28	CURRY FORD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
29	CYPRESSWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
30	DACO - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	DAVENPORT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
32	DESOTO CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	DINNER LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	DUNDEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	EAST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	EAST ORANGE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	FISHEATING CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	8.00
38	FISHEATING CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
39	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	8.00
40	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	110.00	14.00

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

SUBSTATIONS (Continued)

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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
40	2					2
40	2					3
29	2					4
						5
9	1					6
8	1					7
200	1					8
150	1					9
40	2					10
40	2					11
20	1					12
19	2					13
90	3					14
50	2					15
40	2					16
60	2					17
29	2					18
30	1					19
60	2					20
90	3					21
20	1					22
20	1					23
20	1					24
40	2					25
40	2					26
10	1					27
50	1					28
40	2					29
13	1					30
20	1					31
19	2					32
75	2					33
20	1					34
19	2					35
120	3					36
150	1					37
9	1					38
60	1					39
150	1					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
2	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	FOUR CORNERS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	FROSTPROOF - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	HAINES CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	HEMPLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	HOLOPAW - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	25.00	
8	HORSE CREEK #2 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
9	HUNTERS CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	INTERNATIONAL DRIVE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
11	ISLEWORTH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
12	LAKE BRYAN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
13	LAKE BRYAN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	LAKE LUNTZ - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
15	LAKE MARION - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	LAKE OF THE HILLS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	LAKE PLACID - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	LAKE WILSON - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	LAKEWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	LEISURE LAKES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	LITTLE PAYNE CREEK#1-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
23	LITTLE PAYNE CREEK#2-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
24	MAGNOLIA RANCH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	MEADOWS WOODS SOUTH-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
26	MEADOWS WOODS SOUTH-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	MULBERRY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	4.00	
28	NARCOOSEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
29	NORALYN #1 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	12.00	
30	NORALYN #2 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
31	ODESSA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
32	ORANGEWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	PARKWAY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	PEMBROKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	12.00	
35	PINECASTLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	POINCIANA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	REEDY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
38	RIO PINAR - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
39	RIO PINAR - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
40	SAND LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/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.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
200	1					1
9	1					2
60	2					3
50	2					4
80	2					5
60	2					6
25	2					7
9	1					8
60	2					9
100	2					10
19	2					11
500	2					12
90	3					13
30	1					14
20	1					15
20	1					16
40	2					17
60	2					18
40	2					19
55	2					20
9	1					21
13	1					22
13	1					23
13	1	1				24
200	1					25
60	2					26
6	1	1				27
90	3					28
9	3	1				29
9	1	1				30
30	1					31
100	2					32
60	3					33
2	1	1				34
40	2					35
60	2					36
40	2					37
500	2					38
100	2					39
80	2					40

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SAND MOUNTAIN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
2	SEBRING EAST - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	SHINGLE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	SKY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
5	SKY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	SOUTH BARTOW - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	SOUTH FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	25.00	
8	SOUTH FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	4.00	
9	SUNFLOWER - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
10	SUN'N LAKES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	TAFT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
12	TAUNTON RD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	VINELAND - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	WAUCHULA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
15	WEST DAVENPORT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
16	WEST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
17	WEST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	WESTRIDGE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	WEWAHOOTEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	13.00	4.00	
20	WEWAHOOTEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	WHIDDEN CREEK #1 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
22	WINDERMERE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
23	WINDERMERE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24					
25	TOTAL DISTRIBUTION		34439.00	7517.00	360.00
26					
27	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
28	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
29	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	133.00	
30	BROOKSVILLE WEST - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
31	HIGGINS PLANT - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
32	HUDSON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
33	LAKE TARPON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
34					
35	DRIFTON - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	5.00
36	GUMBAY - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
37	HAVANA - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
38	IDYLWILD - NORTH FLORIDA REGION	TRANS - UNATTENDED	138.00	67.00	12.00
39	QUINCY - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	4.00
40	SUWANNEE 230 KV - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00

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SUBSTATIONS (Continued)

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9	1	1				1
20	1					2
60	2					3
250	1					4
90	3					5
9	1					6
19	1					7
45	2					8
30	1					9
40	2					10
60	2					11
20	1					12
60	2					13
19	2					14
19	2					15
250	1					16
13	1	1				17
20	1					18
9	1	1				19
13	1	1				20
20	1					21
200	1					22
40	2					23
						24
24600	567	51				25
						26
750	1					27
250	1					28
250	1					29
250	1					30
250	1					31
500	2					32
1500	2	1				33
						34
105	2					35
75	1					36
75	1					37
150	1					38
75	1					39
400	2					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TALLAHASSEE - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	8.00
2	WILCOX - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
3	ANDERSEN - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	14.00
4	BARBERVILLE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	115.00	66.00	33.00
5	CAMP LAKE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	15.00
6	CENTRAL FLORIDA - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	512.00	230.00	14.00
7	CENTRAL FLORIDA - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
8	CLERMONT EAST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	14.00
9	CRYSTAL RIVER EAST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	116.00	
10	DELAND WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
11	DELAND WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	115.00	67.00	15.00
12	HAINES CREEK - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
13	MARTIN WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
14	ROSS PRAIRIE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	69.00	
15	SORRENTO - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
16					
17	BARCOLA - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
18	GRIFFIN - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	115.00	13.00
19	INTERCESSION CITY - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
20	KATHLEEN - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	512.00	230.00	14.00
21	NORTH BARTOW - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
22	VANDOLAH - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	23.00
23					
24	TOTAL TRANSMISSION		8166.00	3342.00	240.00
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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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.
120	2					1
150	1					2
133	1					3
30	4	1				4
150	1					5
1500	2					6
450	2					7
250	1					8
250	1					9
200	1					10
125	1					11
250	1					12
200	1					13
150	1					14
250	1					15
						16
150	1					17
250	1					18
250	1					19
750	1					20
150	1					21
400	2					22
						23
10788	45	2				24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426 Line No.: 1 Column: g

Single phase units are grouped and reported as a single transformer bank. Individual units are listed as separate line items.

Schedule Page: 426 Line No.: 14 Column: h

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

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Schedule	Page No.

Florida Public Service Commission

Diversification Report

Progress Energy Florida Inc.

December 31, 2005

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, 2005 to December 31, 2005, 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.

4-27-06
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, 2005

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
Robert H. Bazemore, Jr	Controller	None	
Geoff Chatas	Director, Executive Vice President, Chief Financial Officer	None	
		Trustee	Meredith College Raleigh, NC
		Trustee	Wakemed Foundation Raleigh, NC
		Trustee	North Carolina Symphony Raleigh, NC
		Trustee	Raleigh Little Theatre Raleigh, NC
Fred N. Day IV	President & Chief Executive Officer Progress Energy Carolinas	Director	Palmetto Business Forum Columbia, SC
		Director	Advanced Energy Corporation Raleigh, NC
		Director	NC State Engineering Foundation Raleigh, NC
		Director	Triangle Tomorrow Research Triangle Park, NC
		Director	Greater Raleigh Chamber of Commerce Raleigh, NC

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

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
		Director	Assoc. of Edison Illuminating Companies Birmingham, AL
		Director	Southeastern Electric Exchange Atlanta, GA
		Director / Exec VP	Florida Power Corporation
		Director	Microcell Raleigh, NC
		Director / VP	Progress Energy Foundation Raleigh, NC
		Director	N.C. Economic Development Board & Executive Committee Raleigh, NC
Will A. Garrett	PEF Controller	None	
H. Willliam Habermeyer, Jr.	Director, President and CEO	Board Member	Enterprise Florida Orlando, FL
		Board Member & Chair	Pinellas County Education Foundation Largo, FL
		Board Member	Florida Chamber of Commerce Tallahassee, FL

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
		Board Member	Tampa Bay Partnership Tampa, FL
		Board Member	Eckerd College St. Petersburg, FL
		Board Member	USF St. Petersburg Campus St. Petersburg, FL
		Trustee & Vice President	Salvador Dali Museum St. Petersburg, FL
		Board Member	Boys and Girls Club of the Suncoast St. Petersburg, FL
		Board Member	Museum of Fine Arts St. Petersburg, FL
		Director	Raymond James Financial, Inc St. Petersburg. FL
C.S. Hinnant	Senior Vice President & Chief Nuclear Officer	Director	Carolinas Virginia Nuclear Power Assoc. Columbia, SC
		Vice President	Advanced Reactor Corp District of Columbia
William D. Johnson	Director, Group President Energy Delivery	Board Member	Golden LEAF Raleigh, NC

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Affiliation or Connection	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Name and Address
		Board Member	Daugherty Endowment Fund Raleigh, NC
		Board Member	Triangle Opera Raleigh, NC
		Board Chair	Exploris Raleigh, NC
		Board Member	Frankie Lemmon Foundation Raleigh, NC
		Board Member	Rex Hospital Raleigh, NC
		Board Member	North Carolina Citizens for Business & Industry Raleigh, NC
Jeff Lyash	Director, Senior Vice President Chief Financial Officer	None	
John R. McArthur	Director, Senior Vice President	Board of Directors	Easter Seals UCP North Carolina (Resigned March 2005) Raleigh, NC
		Member	N.C. Education Lottery Commission Raleigh, NC
		Board of Directors	Global Transpark Foundation, Inc. Kinston, NC

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Affiliation or Connection	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Name and Address
		Board of Directors	Business - Industry Political Action Committee (BIPAC) Raleigh, NC
		Director	Carolinas Defense Coalition, Inc. Raleigh, NC
Robert B. McGehee	Chairman and CEO	Board Member	WANO, Atlanta Center Atlanta, GA
		Board Member	INPO Atlanta, GA
		Board Member	NEI Washington, D.C.
		Board Member	EEI Washington, D.C.
		Board Member	U.S. Chamber of Commerce Washington, D.C.
William S. Orser	Director, Group President Energy Supply	Board Member	Assoc. of Edison Illuminating Companies Birmingham, AL
		Board Member	NC Partnership for Excellence Morrisville, NC
		President of Board of Directors	Food Bank of North Carolina Raleigh, NC

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

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
		Trustee	Montreat College Montreat, NC
		Co-Chair	The Nature Conservancy Durham, NC
Frank A. Schiller	General Counsel	None	
Peter M. Scott III	Director, Executive Vice President, Chief Financial Officer	Board of Governors Vice Chair	Capital City Club Raleigh, NC
		Director	North Carolina Museum of Art Foundation Raleigh, NC
		Board of Governors Member	RTI International Research Triangle Park, NC
Jeffrey M. Stone	Chief Accounting Officer	None	
Thomas R. Sullivan	Vice President, Treasurer	None	
E. Michael Williams	Senior Vice President	None	

Business Contracts with Officers, Directors and Affiliates

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

List all contracts, agreements, or other business arrangements* entered into during the calendar year (other than compensation-related to position with respondent) between the respondent and each officer and director listed in Part 1 of the Executive Summary. In addition, provide the same information with respect to professional services for each firm, partnership, or organization with which the officer or director is affiliated.

Note: * Business agreement, for this schedule, shall mean any oral or written business deal which binds the concerned parties for products or services during the reporting year or future years.

Name of Officer or Director	Name and Address of Affiliated Entity	Amount	Identification of Product or Service
H. William Habermeyer, Jr	Enterprise Florida Orlando, FL	55,000	Donation
	Pinellas County Education Foundation Largo, FL	57,750	Donation
	Florida Chamber of Commerce Tallahassee, FL	73,000	Donation
	Tampa Bay Partnership Tampa, FL	82,500	Donation
	Salvador Dali Museum St. Petersburg, FL	5,000	Donation
	USF St. Petersburg Campus St. Petersburg, FL	5,000	Donation
	Boys and Girls Club of the Suncoast St. Petersburg, FL	18,100	Donation
Robert B. McGehee	INPO Atlanta, GA	731,884	Dues
	EEI Washington D.C.	24,480	Dues
Peter M. Scott III	Capital City Club Raleigh, NC	2,301	Dues

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

Company: *Progress Energy Florida Inc.* **For the Year Ended December 31, 2005**

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)	$ 3,475,373,829	$ 40,330,727	$ 3,435,043,102	$ 3,475,373,829	$ 40,330,727	$ 3,435,043,101	$ 0
2	Sales for Resale (447)	345,510,905	345,510,905	(0)	345,510,905	345,510,905	-	(0)
3	Total Sales of Electricity	3,820,884,734	385,841,633	3,435,043,101	3,820,884,734	385,841,633	3,435,043,101	0
4	Provision for Rate Refunds (449.1)	(2,289,386)	(1,328,505)	(960,881)	(2,289,386)	(1,328,505)	(960,881)	(0)
5	Total Net Sales of Electricity	3,818,595,348	384,513,128	3,434,082,220	3,818,595,348	384,513,128	3,434,082,220	(0)
6	Total Other Operating Revenues (450-456)	145,406,998	44,417,501	100,989,498	145,406,998	44,417,501	100,989,497	0
7	Other (Specify)							
8								
9								
10	**Total Gross Operating Revenues**	$ 3,964,002,346	$ 428,930,628	$ 3,535,071,718	$ 3,964,002,346	$ 428,930,628	$ 3,535,071,718	$ 0

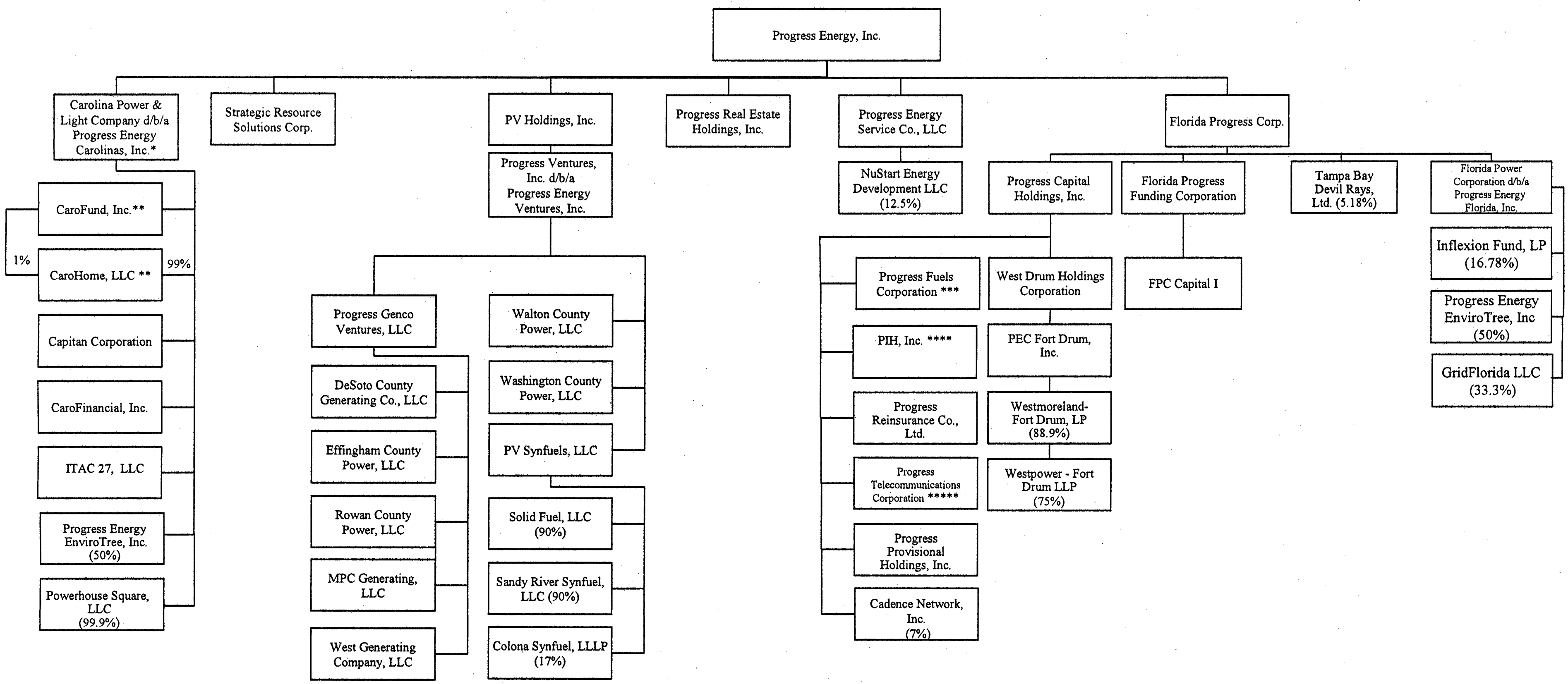
Notes:

Analysis of Diversification Activity
Changes in Corporate Structure
Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

Provide any changes in corporate structure including partnerships, minority interest, and joint ventures and an updated organizational chart, including all affiliates.

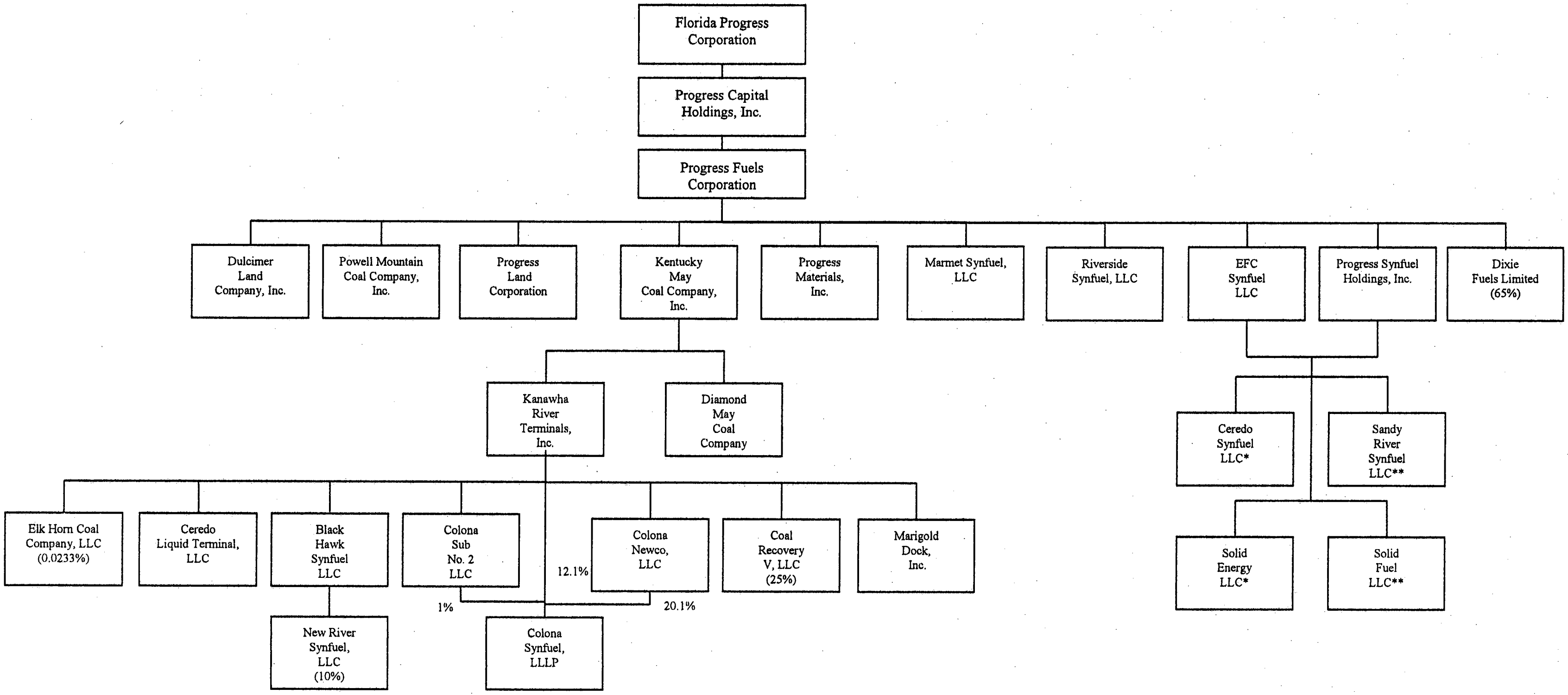
Effective Date (a)	Description of Change (b)
1/1/2005	Progress Point One, LLC was moved from page 1 to page 7 to reflect the fact that it is a passive investment under CP&L.
1/31/2005	Mesa Hydrocarbons, LLC was dissolved.
3/21/2005	Progress Rail Services Corporation (PRSC) created three new Florida Corporations: PFC Property Holdings, Inc., PFC Receivables, Inc., and PFC Huron, Inc. PRSC transferred 3 parcels of real estate to PFC Property Holdings, Inc., various receivables/leasing assets to PFC Receivables, Inc., and a Canadian leasing asset to PFC Huron, Inc.
3/23/2005	PFC Property Holdings, Inc., PFC Receivables, Inc., and PFC Huron, Inc. were transferred, via a dividend distribution, to Progress Fuels Corporation.
3/23/2005	Progress Rail Services Corporation transferred, via a dividend distribution, its membership interest in 3079936 Nova Scotia Company to Progress Fuels Corporation.
3/24/2005	Progress Fuels Corporation sold 100% of the stock of Progress Rail Services Corporation and Progress Rail Metal Reclamation Company to an outside party.
3/31/2005	PRC Huron was determined not to be needed and was dissolved.
5/1/2005	A correction was made to page 7, changing the name of Utech Venture First II, LP to Utech, LLC and the ownership percentage from 9.79% to 11.56%, retroactive to 3/17/2003.
5/1/2005	PTLLC Acquisition Co., LLC was formed as a Delaware LLC whose single member is Progress Telecom, LLC., retroactive to 10/20/2004
5/19/2005	Garrison Gathering, LLC was formed as a Texas LLC whose single member is Talco Midstream Assets, Ltd.
6/23/2005	Progress Energy Carolinas made an investment of $250,000 (0.358% of the stock of the company) in Microcell Corporation, a North Carolina corporation, although additional investments are likely.
7/1/2005	A correction was made to page 1, changing Progress Energy Florida's ownership percentage in Inflexion Fund, LP from 24.44% to 16.78%, retroactive to 6/30/2004.
8/1/2005	Progress Telecom, LLC made an investment in PT Wireless, Inc. Progress Telecom, LLC owns approximately 47% of PT Wireless, Inc., retroactive to June 2005.
8/22/2005	Progress Energy Carolinas made an additional investment of $250,000 in MicroCell Corporation, a North Carolina corporation. PEC's ownership percentage is now 0.714%.
9/30/2005	Cape Fear Energy Corp., a first tier subsidiary of Progress Energy, Inc., was dissolved.

Progress Energy, Inc.
Corporate Legal Entity Structure



* Excludes passive investments held by CP&L in low-income housing projects, venture capital projects, enterprise development projects, etc. – see page 7.
** CaroHome LLC and CaroFund, Inc. own various interests in low-income housing and historical properties-see page 8. CaroHome, LLC is owned 99% by CP&L and 1% by Carofund, Inc.
*** See Progress Fuels subsidiaries on pages 2, 3, and 4.
**** See PIH subsidiaries on page 5.
***** See Progress Telecommunications subsidiaries on page 6.
Note: Progress Energy or its subsidiaries own 100% of the voting securities of the subsidiaries or associate companies shown on the chart unless otherwise noted with other percentage interests.

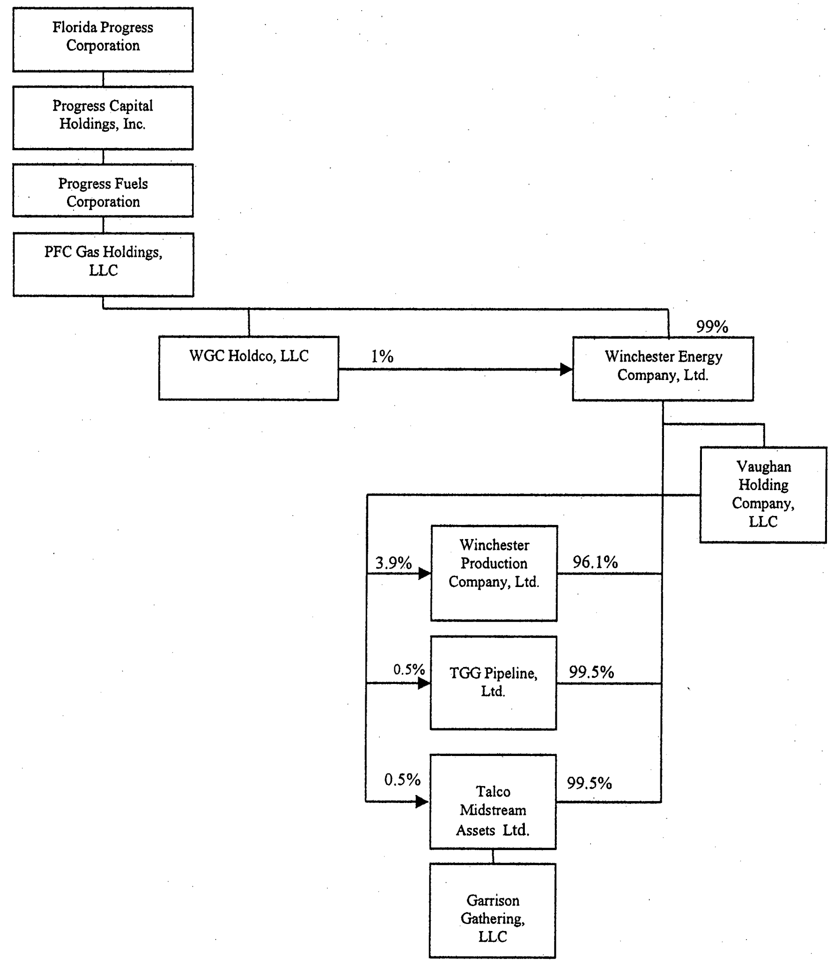
Progress Fuels Corporation
Energy & Related Services Group



* EFC Synfuel LLC and Progress Synfuel Holdings, Inc. own 99% and 1%, respectively.
** EFC Synfuel LLC and Progress Synfuel Holdings, Inc. own 9% and 1%, respectively.

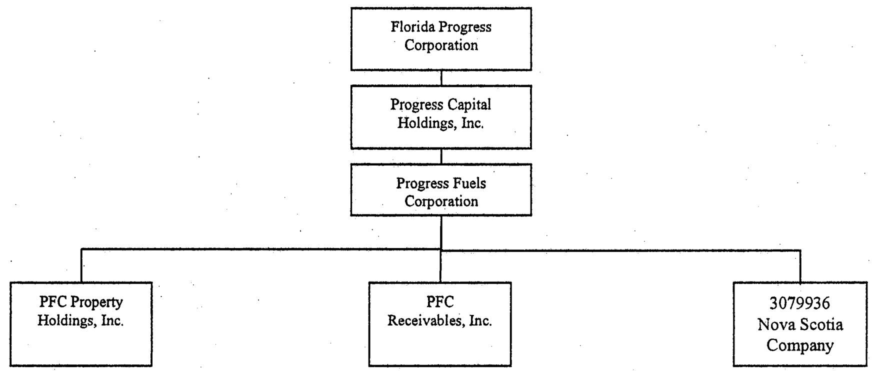
12-31-05

Progress Fuels Corporation
Gas Operations Group

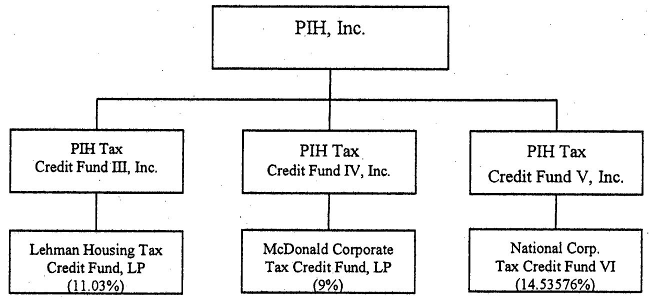


12-31-05

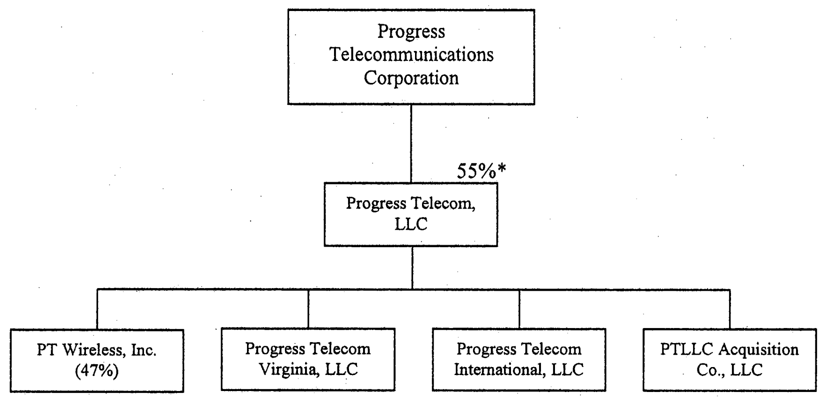
Progress Fuels Corporation
Rail Services Group



PIH, Inc.


PIH, Inc.
PIH Tax Credit Fund III, Inc.
PIH Tax Credit Fund IV, Inc.
PIH Tax Credit Fund V, Inc.
Lehman Housing Tax Credit Fund, LP (11.03%)
McDonald Corporate Tax Credit Fund, LP (9%)
National Corp. Tax Credit Fund VI (14.53576%)

Telecommunications Group



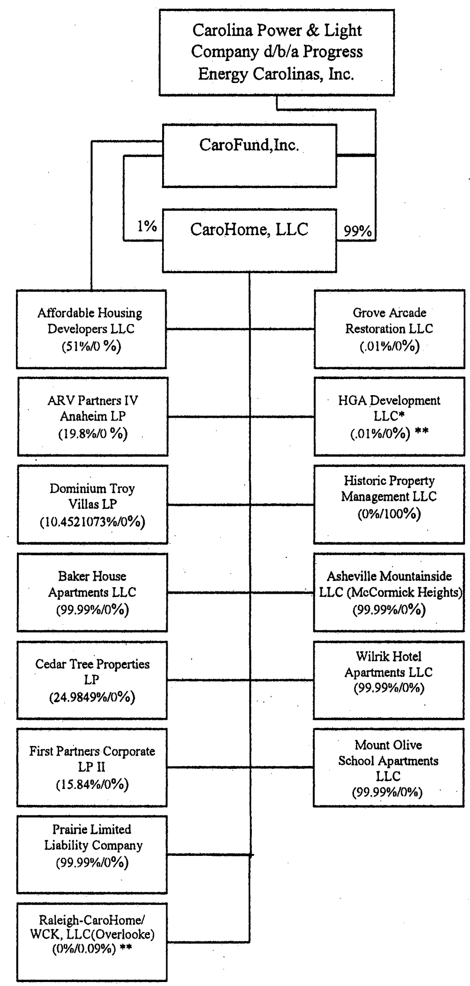
*Remaining 45% interest is owned by EPIK Communications, Inc., an unrelated third party

Progress Energy Carolinas (CP&L)
Other Investments

- Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.
  - North Carolina Enterprise Fund, LP (5.00877%)
  - Absolut LP (99%)
  - Capital City Low Income Housing LP (99%)
  - NC Enterprise Corporation (4.97%)
  - Progress Point One, LLC (50%)
  - Microcell Corporation (0.714%)
  - Walnut Street LP (99%)
  - Utech Climate Challenge Fund LP (9.76%)
  - Carousel Capital Partners LP (3.06857%)
  - Better Homes for Garner LP (99%)
  - Kinetic Ventures I LLC (11.111111%)
  - Maxey Flats LLC (3%)
  - Pantellos Corporation (1%)
  - Kinetic Ventures II, LLC (14.282715%)
  - South Atlantic Private Equity Fund IV, LP (10.133794%)
  - Utech, LLC (11.56%)
  - WNC Institutional Tax Credit Fund LP (99%)*
  - EBS Litigation LLC (0.00126%)
  - EBS, Pension, LLC (0.00126%)
  - EBS Building LLC (0.00126%)
  - Southeast Regional Park Industrial Development Company, LLC (33.33%)

*Consolidated Entity for Financial Statement Purposes

CaroHome / CaroFund Investments



Note: CaroHome % listed first, then CaroFund %

*Also owned 0.01% by Historic Property Management LLC

**Consolidated Entity for Financial Statement Purposes

Analysis of Diversification Activity
New or Amended Contracts with Affiliated Companies

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2005

Provide a synopsis of each new or amended contract, agreement, or arrangement with affiliated companies for the purchase, lease, or sale of land, goods, or services (excluding tariffed items). The synopsis shall include, at the minimum, the terms, price, quantity, amount and duration of the contracts.

Name of Affiliated Company (a)	**Synopsis of Contract (b)**
Progress Ventures, Inc. (PFC) d/b/a Progress Energy Ventures, Inc.	Sale of one Combustion Turbine Generator. Bill of Sale and Assignment and Assumption Agreement whereby PFC agreed to sell to PEF a combustion turbine generator and assign to PEF the rights related to the CT designated Unit No. 2 under a Purchase Agreement dated January 31, 2002 between PFC and GE Power Systems Business. PEF agreed to assume from PFC the obligations and duties under the Purchase Agreement. Effective date: January 14, 2005 Purchase price: $ 17,198,000.00
Progress Materials, Inc. (PMI)	Ash Management Contract between PEF and PMI. The combustion of coal used by PEF at its crystal River Coal Plant units 1, 2, 4 and 5 produces byproducts known as fly ash and bottom ash which PEF will sell to PMI. PMI has the ability to maximize ash utilization, to minimize ash landfill disposal and related environmental concerns, to reduce operating costs and provide a reliable revenue stream for PEF. PMI has developed and patented an ash beneficiation technology called Carbon Burn-Out (CBO) that utilizes high-carbon ash which would otherwise be discarded. Effective date: 9/2/2005 Term of agreement : ten (10) year initial period Bottom Ash and Fly Ash Base price from Units 1, 2, 4 and 5: $ 1.50/ton Base prices shall be adjusted up or down as of January 1 each year to the extent the Producer Price Index changes during the term of the agreement. However the adjusted price shall not be less than $1.50/ton Process water for Aardelite Process: $100.00/month Potable water for sanitary purposes $ 30.00/month Disposal charge by PMI for Unmarketable or $ 3.50/ton

Analysis of Diversification Activity
New or Amended Contracts with Affiliated Companies

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2005

Provide a synopsis of each new or amended contract, agreement, or arrangement with affiliated companies for the purchase, lease, or sale of land, goods, or services (excluding tariffed items). The synopsis shall include, at the minimum, the terms, price, quantity, amount and duration of the contracts.

Name of Affiliated Company (a)	Synopsis of Contract (b)
Progress Materials, Inc. (PMI)	Lease between PEF as lessor and PMI as lessee for property located in Citrus County, Florida for the purpose of constructing and operating to manufacture Aardelite. Lease made in conjunction with the Ash Management Contract above. Effective date: 12/14/2004 Term: Co terminus with the terms of the Ash Management Contract Annual rent $8,846.00 per year in advance of each twelve (12) month period. Rental for each year subsequent to the initial year is subject to escalation or reduction based on the Consumer Price Index (CPI Index) providing that the rent shall never decrease below $9,000.00/year.

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

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2005

Provide information regarding individual affiliated transactions in excess of $500,000. Recurring monthly affiliated transactions which exceed $500,000 per month should be reported annually in the aggregate. However, each land or property sales transaction even though similar sales recur, should be reported as a "non-recurring" item for the period in which it occurs.

Name of Affiliate (a)	Description of Transaction (b)	Dollar Amount (c)
Progress Energy Service Company LLC	Recurring Employee benefits, Legal, IT, Acctg Svcs, Telecom, HR, Corp Comm, Risk Mgmt, Environmental Svcs, Corp Mgmt, Shared Corporate Svcs	233,393,763
Progress Fuels Corporation	Recurring coal purchases for Crystal River, barge charges	394,567,979
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Recurring Gas purchases, Mgmt & IT services, Fuel procurement, Mgmt services, Customer Service support	53,648,049
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Recurring Gas sales, Fuel sales, Mgmt services, Customer Service support	13,951,994

Analysis of Diversification Activity
Summary of Affiliated Transfers and Cost Allocations

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

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)	Native Load Generation, Common Nuc Svcs, Transmission/distribution support, Tech Svcs Support, Core Environmental Svcs, CT Ops/Maint, Outside Support Svcs, Energy Delivery Mgmt/Oversight Common Cust Svcs Support, Generation expansion, Power Ops mgmt/finance	Utility Service Agreement 1/1/2001	S	1460001	13,951,994
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Native Load Generation, Transmission/distribution support, Common Nuclear Svcs, Tech Svcs support, Core Environmental Svcs, CT Ops/Maint, Outside Support Svcs, Wireless Carrier Svcs, Nonreg Trans Eng & Design, Nonreg Trans Maint Svcs, Nonreg T&D Svcs, Regulated Timber sales, Reg Accounting Fleet Ops/Maint, T&D support, Energy Delivery Mgmt/Oversight, Meterine Svcs, Contract Svcs, Customer Svc Mgmt, Common Cust Svcs, Energy Supply Mgmt & Finance, Nucler Mgmt, Engineering, RCO Support, Mtls & Contract Suport, Nuclear IT, Generation Expansion, Tech Svcs Support	Utility Service Agreement 1/1/2001	P	2340001	53,648,049
Progress Energy Ventures	Energy Trading Mgmt, Technical Support Svcs, Core Env Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460020	597,369
Progress Energy Ventures	Combustion Turbine Generator	Bill of Sale 1/14/2005	P	15420PP	17,198,000
Progress Energy Ventures	Labor	Utility Service Agreement 11/1/2002	P	2320601	16,981
Rowan County Power, LLC	Technical Support Svcs, Core Env Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460024	18,710
Effingham County Power, LLC	Technical Support Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460025	19,198
DeSoto County Generating Company LLC	Technical Support Svcs, Core Env Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460026	28,840
DeSoto County Generating Company LLC	Transmission Maint/Repair Svcs	Utility Service Agreement 11/1/2002	S	1433110	49,379

Analysis of Diversification Activity
Summary of Affiliated Transfers and Cost Allocations

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2005

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)
MPC Generating, LLC	Technical Support Svcs, Core Env Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460032	3,190
MPC Generating, LLC	Inventory (one time)		P	2340032	985
Walton County Power, LLC	Technical Support Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460033	3,573
Washington County Power, LLC	Technical Support Svcs, CT Ops/Maint	Utility Service Agreement 11/1/2002	S	1460034	4,476
Progress Fuels Corporation	Property Rental, Aardelite sales, Fly Ash sales, Potable & Process Water sales	Ash Management Contract Extensions 9/1/1995 and 9/2/2005	S	1460061	622,203
Progress Fuels Corporation	Coal, Outside Services	Utility Service Agreement 11/1/2002	P	2340061	394,567,979
Progress Rail Services Corporation[1]	Inventory (one time)		P	2320601	1,755
Progress Telecom LLC	Network Services, Land/Pole IRU, Revenue Sharing	IRU and Master Service and Wireless Attachment Agreements - 12/19/2003	S	1460067	3,213,997
Progress Telecom LLC	Network Maint/Repair Svcs	Master Service and Wireless Attachment Agreement - 12/19/2003	S	1433120	17,566
Progress Materials, Inc.	Fly Ash Sales, Potable & Process Water Sale	Ash Management Contract - 9/1/1995	S	1433055	270,045
Progress Energy Service Company LLC	Labor	Utility Service Agreement 1/1/2001	S	1460098	4,040,469
Progress Energy Service Company LLC	Legal, IT, Acctg Svcs, Telecom, Public Affairs, HR, Corp Comm, Tax Svcs, Risk Mgmt, Environmental Svcs, Corp Mgmt, Treasury, Risk Mgmt, Disbursement Svcs, Other Shared Corp Svcs	Utility Service Agreement 12/1/2000	P	2340098	233,393,763

[1] Period reported 1/1/05 through 3/23/05. On 3/24/05 100% of the stock of Progress Rail Services Corporation was sold to an outside party.

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

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2005

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

Name of Affiliate	Description of Asset or Right	Cost/Orig. Cost	Accumulated Depreciation	Net Book Value	Fair Market Value	Purchase Price	Title Passed Yes/No
Purchases from Affiliates:							
Progress Ventures, Inc. (PFC) d/b/a Progress Energy Ventures, Inc.	GE 7FA Turbine	$ 40,559,220	-	$ 17,198,000	$ 17,198,000	$ 17,198,000	Yes
Total		$ 40,559,220	-	$ 17,198,000	$ 17,198,000	$ 17,198,000	
Sales to Affiliates:		$	$	$	$	**Sales Price**	
			None				
Total						$	

Analysis of Diversification Activity
Employee Transfers

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2005

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

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
PEF	PEC	Supv-Dist Asset Ops (IO)	Supv-Dist Asset Ops (IO)	Permanent
PEF	SVC	Environmental Specialist	Environmental Specialist	Permanent
PEF	PEC	Lead Engr Technical Supt Spec	Lead Engr Technical Supt Spec	Permanent
PEF	PEC	Sr Engr	Sr Engr	Permanent
PEF	SVC	Sr Engr	Sr Engr	Permanent
PEF	PEC	Plant Services Assistant I-FL	Plant Services Assistant I-FL	Permanent
PEF	PEC	Mgr-Transmission Area Maint	Gen Mgr-Trans Maint	Permanent
PEF	PEC	Region Service Coordinator-ED	Region Service Coordinator-ED	Permanent
PEF	SVC	Lead Environmental Specialist	Lead Environmental Specialist	Permanent
PEF	SVC	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
PEF	PEC	Mechanic-SM	Mechanic-SM	Permanent
PEF	SVC	Telecomms Tech	Telecomms Tech	Permanent
PEF	PEC	NDE Tech III	Data Management Asst I-FL	Permanent
PEF	SVC	Distribution Inspector-ED	Distribution Inspector-ED	Permanent
PEF	SVC	Supv-Meter Shop Services	Supv-Meter Shop Services	Permanent
PEF	PEC	Bus Fin Anlyst	Bus Fin Anlyst	Permanent
PEF	PEC	Mechanic-SM	Mechanic-SM	Permanent
PEF	SVC	Environmental Specialist	Environmental Specialist	Permanent
PEF	PEC	Mechanic-SM	Mechanic-SM	Permanent
PEF	PEC	Mechanic-SM	Mechanic-SM	Permanent
PEF	PEC	Supv-Distribution Field	Supv-Distribution Field	Permanent
PEF	SVC	Lead Environmental Specialist	Lead Environmental Specialist	Permanent
PEF	PEC	Data Management Asst I-FL	Mech 3/C	Permanent
PEF	SVC	Princ Environmental Specialist	Princ Environmental Specialist	Permanent
PEF	PEC	Region Service Coordinator-ED	Region Service Coordinator-ED	Permanent
PEF	SVC	Lineman	Lineman	Permanent
PEF	SVC	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
PEF	SVC	Sr Administrative Assistant-FL	Sr Administrative Assistant-FL	Permanent
PEF	SVC	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
PEF	PEC	Sr Bus Fin Anlyst	Sr Bus Fin Anlyst	Permanent
EFC	PEF	Coal Scheduler-RF	Coal Scheduler-RF	Permanent
PEF	SVC	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
PEF	SVC	Admin Assistant I	Admin Assistant I	Permanent
PEF	SVC	Supv-Fleet Services Ctr	Mgr-Fleet Maintenance	Permanent
PEF	SVC	Data Management Asst I-FL	Data Management Asst I-FL	Permanent
PEF	PEC	Mgr-Distribution Ops	Mgr-Distribution Ops	Permanent
PEF	SVC	Energy Efficiency Spec-EDG	Energy Efficiency Spec-EDG	Permanent
PEF	PEC	Sr Bus Fin Anlyst	Lead Bus Fin Anlyst	Permanent
PEF	SVC	Assoc Engr Technical Supt Spec	Assoc Engr Technical Supt Spec	Permanent
PEF	PEC	Technical Support Asst II-FL	Technical Support Asst II-FL	Permanent
PEF	SVC	Admin Assistant I	Admin Assistant I	Permanent
PEF	SVC	Technical Support Asst I-FL	Technical Support Asst I-FL	Permanent
PEF	PEC	Sr Craft/Technical Trainer	Sr Craft/Technical Trainer	Permanent
PEF	SVC	Environmental Specialist	Environmental Specialist	Permanent
PEF	SVC	Cons Affairs Anlyst-EDG	Cons Affairs Anlyst-EDG	Permanent
PEF	PEC	Mechanic-SM	Mechanic-SM	Permanent
PEF	SVC	Lead Environmental Specialist	Lead Environmental Specialist	Permanent
PEF	PEC	Mechanic-SM	Mechanic-SM	Permanent
PEF	SVC	Sr Environmental Specialist	Sr Environmental Specialist	Permanent

Analysis of Diversification Activity
Employee Transfers

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

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

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
PEF	SVC	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
PEF	PEC	Cert Welder Mech-SM	Cert Welder Mech-SM	Permanent
PEF	SVC	Sr Acquisition Agent	Sr Acquisition Agent	Permanent
PEF	PEC	Bus Fin Anlyst	Bus Fin Anlyst	Permanent
PEF	PEC	Mechanic-SM	Mechanic-SM	Permanent
PEF	PEC	Mechanic-SM	Mechanic-SM	Permanent
PEF	SVC	Mgr-Environ Proj and Strategy	Mgr-Env Ener Sup & CCO-FL	Permanent
PEF	PEC	Sr ED Project Analyst	Sr ED Project Analyst	Permanent
PEF	SVC	Mgr-Distribution Ops	Mgr-Distribution Ops	Permanent
PEC	PEF	Mgr-Call Services-ED	Mgr-Call Services-ED	Permanent
PEC	PEF	Assoc Engr	Assoc Engr	Permanent
PEC	PEF	Dir-Environmental Svcs-POG	Dir-Environmental Svcs-POG	Permanent
PEC	PEF	Sr Engr	Sr Engr	Permanent
PEC	PEF	Line & Serv Tech 1/C	Line & Serv Tech 1/C	Permanent
PEC	PEF	Sr ED Project Analyst	Sr ED Project Analyst	Permanent
SVC	PEF	Sr Legal Secretary-FL	Sr Legal Secretary-FL	Permanent
PEC	PEF	Sr Bus Fin Anlyst	Sr Bus Fin Anlyst	Permanent
PVI	PEF	Mgr-Plant Production-CT	Plt Mgr-CT-Suncoast	Permanent
PEC	PEF	Sr Bus Fin Anlyst	Sr Bus Fin Anlyst	Permanent
SVC	PEF	Administrative Assistant I-FL	Administrative Assistant I-FL	Permanent
PEC	PEF	Data Mgmt Asst I	Data Mgmt Asst I	Permanent
PEC	PEF	INPO Loanee	INPO Loanee	Permanent
PEC	PEF	Supv-Live Line Bare Hand	Supv-Trans Line Maint	Permanent
SVC	PEF	Data Management Asst I-FL	Data Management Asst I-FL	Permanent
PVI	PEF	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
SVC	PEF	Sr Bus Fin Anlyst	Lead Bus Fin Anlyst (INT)	Temporary (NA)
SVC	PEF	IT Analyst	IT Analyst	Permanent
SVC	PEF	IT Analyst	IT Analyst	Permanent
SVC	PEF	Audit Manager	Audit Manager	Permanent
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
PEC	PEF	Cust Service Agent I	Cust Service Agent I	Permanent
EFC	PEF	Coal Scheduler-RF	Coal Scheduler-RF	Permanent
PEC	PEF	Mgr-CIG Sales & Svc-Acct Mgmt	Mgr-CIG Sales & Svc-Acct Mgmt	Permanent
PEC	PEF	Sr IT Analyst	Sr IT Analyst	Permanent
PEC	PEF	Dispatching Tech I	Dispatching Tech I	Permanent
PVI	PEF	Sr Enrgy Portf Mgmt Spec-PV	Sr Enrgy Portf Mgmt Spec-PV	Permanent
SVC	PEF	Lead Auditor	Lead Auditor	Permanent
SVC	PEF	Assoc Engr Technical Supt Spec	Assoc Engr Technical Supt Spec	Permanent
SVC	PEF	Sr Auditor	Sr Auditor	Permanent
PEC	PEF	Sr Bus Fin Anlyst	Sr Bus Fin Anlyst	Permanent
PEC	PEF	Supt-Operations & Results-FGD	Supt-Operations & Results-FGD	Permanent
PEC	PEF	Mgr-Perform&ProcImprov-ED	Mgr-Perform&ProcImprov-ED	Permanent
PEC	PEF	Sr Cust Service Agent	Sr Cust Service Agent	Permanent
PEC	PEF	Sr Cust Service Agent	Sr Cust Service Agent	Permanent
SVC	PEF	Administrative Assistant I-FL	Administrative Assistant I-FL	Permanent

Analysis of Diversification Activity
Employee Transfers

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

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

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
SVC	PEF	Sr Auditor	Sr Auditor	Permanent

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

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2005

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)
Wireless Transmission Tower Attachments	4540001	Regulated
Rent from Electric Properties	4540000	Regulated
PCS Engineering Design and Construction	4170000	Non-Regulated
Managed Services	4170000	Non-Regulated
Turnkey Solutions	4170000	Non-Regulated
Power Quality Services	4170000	Non-Regulated
Homewire	4170000	Non-Regulated
Lighting	4170000	Non-Regulated
Infrared Scanning Services	4170000	Non-Regulated
High Voltage Services	4170000	Non-Regulated
Distribution Services	4170000	Non-Regulated
Vegetation Services	4170000	Non-Regulated
Metering Services	4170000	Non-Regulated
Transformer Services	4170000	Non-Regulated
Material Solutions	4170000	Non-Regulated
Joint Trenching	4170000	Non-Regulated
Off System Power Marketing	4170000	Non-Regulated

Nonutility Property (Account 121)

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

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	531,940	-4,575	527,365
Not Previously Devoted to Public Service			
Land - Volusia County, Florida	2,752,511		2,752,511
Equipment - Meters System (Florida)	4,770,442	170,969	4,941,411
Equipment - Walk of Fame, St. Pete, FL	1,380,193		1,380,193
Other	234,775	10,504	245,279
Communication Equipment	9,272,430		9,272,430
Totals	$ 19,254,493	$ 176,898	$ 19,431,391

Number of Electric Department Employees

Company: ***Progress Energy Florida Inc.***
For the Year Ended December 31, 2005

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)	**10/30/2005**
2. Total Regular Full-Time Employees	**3880**
3. Total Part-Time and Temporary Employees	**520**
4. Total Employees	**4400**

Details

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2005

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

(a) Miscellaneous Amortization (Account 425): Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions: Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less then 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Item	Amount Debit / (Credit)
Account 426 - Miscellaneous Income Deductions	
Donations	
Civic & Community Organizations	328,151.18
Cultural & Arts Organizations	221,050.00
Economic Development	568,026.24
Education Related Contributions	470,742.89
Environment	110,598.00
Health & Human Services Contributions	173,500.00
Other	$121,319.04
Progress Energy Foundations	3,900,000.00
Subtotal Accounts 4261014, 426180T, 4261BUD	$5,893,387.35
Investment in Company Owned Life Insurance	(2,123,064.40)
Subtotal Accounts 4262016, 4262041	(2,123,064.40)
Penalties	4,349.70
Subtotal Account 4263001	4,349.70
Certain Civic, Political & Related Activities	3,730,609.97
Subtotal Accounts 4264100, 4264200, 4264300	3,730,609.97
Other Deductions	3,692,583.16
Subtotal Account 4265001	3,692,583.16
Total Miscellaneous Income Deductions - Account 426	11,197,865.78
Account 430 - Interest on Debt to Associated Companies	
Money Pool (Avg Rate 3.8%)	3,215,111.27
Total Interest on Debt to Associated Companies - Account 430	3,215,111.27
Account 431 - Other Interest Expense	
Commitment Fees (4310010)	815,258.63
Other Interest Expense (4310001, 4310011)	412,911.74
Customer Deposits - Rate 6 to 7% per annum	8,279,369.09
Interest related to Projected Tax Refund - Rate 6.5%	(4,684,553.00)
Interest related to Projected Tax Deficiency on various audit issues - Rate 6.5%	291,957.19
Total Other Interest Expense - Account 431	5,114,943.65