Progress Energy

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Serial: PE&RAS-05-015
March 31, 2005

United States Nuclear Regulatory Commission
ATTENTION: Document Control Desk
Washington, DC 20555-0001

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324 / LICENSE NOS. DPR-71 AND DPR-62

CRYSTAL RIVER UNIT 3 NUCLEAR GENERATING PLANT
DOCKET NO. 50-302 / LICENSE NO. DPR-72

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT NO. 1
DOCKET NO. 50-400 / LICENSE NO. NPF-63

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261 / LICENSE NO. DPR-23

BIENNIAL DECOMMISSIONING FUNDING STATUS REPORT

Ladies and Gentlemen:

Pursuant to 10 CFR 50.75(f)(1), Carolina Power & Light Company, now doing business as Progress Energy Carolinas, Inc. (PEC), and Florida Power Corporation, now doing business as Progress Energy Florida, Inc. (PEF), submit this biennial status report for funding the decommissioning of each reactor listed above. The specific information required by 10 CFR 50.75(f)(1) is listed on Attachments 1 through 5.

Pursuant to 10 CFR 50.75(e)(1)(ii) and as previously reported, PEC has authorization from the rate-setting authority of North Carolina to use a real rate of return greater than 2% for the North Carolina portion of the decommissioning trust fund. For the North Carolina portion of the trust fund, the assumed real rate of return is 3.25%. The 3.25% real rate of return is less than the 3.75% real rate of return which has been reviewed by Public Staff of the North Carolina Utilities Commission (NCUC) and found to be reasonable. In particular, the Public Staff reviewed the Decommissioning Cost and Funding Report filed on June 18, 1999, which indicated an assumed earnings rate of 7.75% and a cost escalation rate of 4% (real rate of return of 3.75%). The Public Staff subsequently filed a report to the NCUC on January 7, 2000, in which they stated, "The Public Staff's review of ... Annual Nuclear Decommissioning Trust Fund Report indicates that ... investment practices for external investment funds appear to be reasonable." At the time of the filing, there was no non-qualified portion of the decommissioning trust fund; the entire decommissioning trust fund was a qualified fund. When the decommissioning trust fund was later segregated between a qualified portion and a non-qualified portion, a consistent real rate of return was used for the entire decommissioning trust fund.

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As of December 31, 2004, the total PEC assets in the trust funds, qualified and non-qualified, were approximately allocated as 49.3%, 35.8%, 6.6%, and 8.3% for Domestic Equity, Domestic Fixed Income, International Equity, and Municipal Bonds, respectively.

As of December 31, 2004, the total PEF assets in the trust funds, qualified and non-qualified, were approximately allocated as 46.0%, 22.8%, 14.3%, and 16.9% for Domestic Equity, Domestic Fixed Income, International Equity, and Municipal Bonds, respectively.

As previously established by letter PE&RAS-03-017 to the NRC, dated March 28, 2003, PEC uses a combination of an external sinking fund and a parent company guarantee to provide the required financial assurance of decommissioning funds for the Brunswick Steam Electric Plant, Unit Nos. 1 and 2, pursuant to 10 CFR 50.75(e)(1)(iii)(B). Consistent with the guidance in Appendix B-6.5 of Regulatory Guide 1.159, the parent company guarantees were written to require the annual submittal to the NRC of certain documents for Progress Energy, Inc., including: the enclosed Form 10-K (containing financial statements) which was filed with the U.S. Securities and Exchange Commission; financial test data; and special auditor's report and reconciling schedule.

This document contains no new regulatory commitment.

As a convenience to the NRC, the biennial status report from the North Carolina Eastern Municipal Power Agency (NCEMPA) is enclosed for funding the decommissioning of the reactors, which are identified in Attachments 2, 3, and 4. However, neither co-owner assumes any responsibility for the information contained in the other's report.

Also enclosed, as a convenience to the NRC, is the status report from each CR3 Participant for funding the decommissioning of the reactor identified in Attachment 5. However, none of the Participants assumes any responsibility for the information contained in any other Participant's report.

Please contact me at (919) 546-6901 if you need additional information concerning this report.

Sincerely,

Chris Burton

Chris Burton
Manager - Performance
Evaluation & Regulatory Affairs

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Attachments:

- Attachment 1, Status of Financial Assurance Mechanism, H. B. Robinson Steam Electric Plant, Unit No. 2
- Attachment 2, Status of Financial Assurance Mechanism, Brunswick Steam Electric Plant, Unit No. 1
- Attachment 3, Status of Financial Assurance Mechanism, Brunswick Steam Electric Plant, Unit No. 2
- Attachment 4, Status of Financial Assurance Mechanism, Shearon Harris Nuclear Power Plant, Unit No. 1
- Attachment 5, Status of Financial Assurance Mechanism, Crystal River Unit 3 Nuclear Generating Plant

Enclosures:

- Form 10-K for Progress Energy, Inc. for Year Ended December 31, 2004 (226 pages)
- Letter from Chief Financial Officer of Progress Energy, dated March 24, 2005, with Financial Test: Alternative II (2 pages)
- Letter from Deloitte & Touche, Independent Accountants' Report on Applying Agreed-Upon Procedures, dated March 25, 2005, with Schedule Reconciling Amounts Contained in Financial Test with Amounts in Financial Statements, and Financial Test (4 pages)
- ElectricCities of North Carolina, Inc. Status Report for Decommissioning Financial Assurance, dated March 28, 2005 (4 pages)
- City of Alachua Status Report for Decommissioning Financial Assurance (1 page)
- City of Bushnell Status Report for Decommissioning Financial Assurance (1 page)
- City of Gainesville Status Report for Decommissioning Financial Assurance (1 page)
- City of Kissimmee Status Report for Decommissioning Financial Assurance (1 page)
- City of Leesburg Status Report for Decommissioning Financial Assurance (1 page)
- City of New Smyrna Beach Status Report for Decommissioning Financial Assurance (1 page)
- City of Ocala Status Report for Decommissioning Financial Assurance (1 page)
- Orlando Utilities Commission Status Report for Decommissioning Financial Assurance (1 page)
- Seminole Electric Cooperative, Inc. Status Report for Decommissioning Financial Assurance (1 page)

c: without Form 10-K:
W. D. Travers, Regional Administrator – Region II
USNRC Resident Inspector – BSEP, Unit Nos. 1 and 2
USNRC Resident Inspector – CR3
USNRC Resident Inspector – SHNPP, Unit No. 1
USNRC Resident Inspector – HBRSEP, Unit No. 2
B. L. Mozafari, NRR Project Manager – BSEP, Unit Nos. 1 and 2; CR3
C. P. Patel, NRR Project Manager – SHNPP, Unit No. 1; HBRSEP, Unit No. 2
M. A. Dusaniwskyj – USNRC NRR/DRIP/RPRP-OWFN, 12 D3
J. A. Sanford – North Carolina Utilities Commission
B. L. Baez – Florida Public Service Commission

Attachment 1
Status of Financial Assurance Mechanism

H. B. Robinson Steam Electric Plant, Unit No. 2 Docket No. 50-261 / License No. DPR-23

- Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c)

  $337 million at expiration of current license, July 31, 2030

  $219 million estimated to be required from North Carolina
  $118 million estimated to be required from All Others

- Amount of decommissioning funds accumulated as of December 31, 2004

  $165,263,918

  $106,492,499 accumulated from North Carolina
  $58,771,419 accumulated from All Others

- Schedule of the annual amounts remaining to be collected

NRC Required Minimum:	**$0.6 million** $0.0 million required annually from North Carolina $0.6 million required annually from All Others
Allowed by North Carolina Utilities Commission and Public Service Commission of South Carolina:	**$9,436,965** $7,720,987 to be collected annually from North Carolina $1,715,978 to be collected annually from South Carolina
Under wholesale contracts:	**$1,528,181** (contribution is not credited in future years)

- Assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections

Rate of escalation in decommissioning costs =	**0%**
Rate of earnings on decommissioning funds =	**3.25% (North Carolina)** **2% (All Other Contributions)**

  For wholesale contracts, the resultant assumed real rate of return of 2% is only applicable to funds accumulated from previous contributions associated with those contracts.

- Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v)

  None

- Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report

  Letter PE&RAS-04-061, dated May 12, 2004, provided notification of the decision to change the decommissioning funding method for the H. B. Robinson Steam Electric Plant, Unit No. 2 (RNP) by terminating the use of the parent company guarantee.

- Material changes to trust agreements

  None

Attachment 2
Status of Financial Assurance Mechanism

Brunswick Steam Electric Plant, Unit No. 1 **Docket No. 50-325 / License No. DPR-71**

- Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c)

  $442 million at expiration of current license, September 8, 2016

  Progress Energy Carolinas, Inc. share (81.67%) = $361 million

  $234.3 million estimated to be required from North Carolina
  $126.3 million estimated to be required from All Others

- Amount of decommissioning funds accumulated as of December 31, 2004

  $145,947,577

  $93,314,629 accumulated from North Carolina
  $52,632,948 accumulated from All Others

- Schedule of the annual amounts remaining to be collected

  Having satisfied the financial tests pursuant to Appendix A.II.C.1 to 10 CFR 30, Progress Energy, Inc., the parent company of Progress Energy Carolinas, Inc., guarantees to provide $73 million for decommissioning.

NRC Required Minimum:	**$11.52 million** $6.96 million required annually from North Carolina $4.56 million required annually from All Others
Allowed by North Carolina Utilities Commission and Public Service Commission of South Carolina:	**$6,075,477** $4,934,785 to be collected annually from North Carolina $1,140,692 to be collected annually from South Carolina
Under wholesale contracts:	**$1,442,478** (contribution is not credited in future years)

- Assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections

Rate of escalation in decommissioning costs =	**0%**
Rate of earnings on decommissioning funds =	**3.25% (North Carolina)** **2% (All Other Contributions)**

  For wholesale contracts, the resultant assumed real rate of return of 2% is only applicable to funds accumulated from previous contributions associated with those contracts.

- Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v)

  None

- Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report

  None

- Material changes to trust agreements

  None

Attachment 3
Status of Financial Assurance Mechanism

Brunswick Steam Electric Plant, Unit No. 2 **Docket No. 50-324 / License No. DPR-62**

- Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c)

  $442 million at expiration of current license, December 27, 2014

  Progress Energy Carolinas, Inc. share (81.67%) = $361 million

  $234.3 million estimated to be required from North Carolina
  $126.3 million estimated to be required from All Others

- Amount of decommissioning funds accumulated as of December 31, 2004

  $161,128,975

  $103,023,785 accumulated from North Carolina
  $58,105,190 accumulated from All Others

- Schedule of the annual amounts remaining to be collected

  Having satisfied the financial tests pursuant to Appendix A.II.C.1 to 10 CFR 30, Progress Energy, Inc., the parent company of Progress Energy Carolinas, Inc., guarantees to provide $96 million for decommissioning.

NRC Required Minimum:	**$12.88 million** $7.86 million required annually from North Carolina $5.02 million required annually from All Others
Allowed by North Carolina Utilities Commission and Public Service Commission of South Carolina:	**$4,455,309** $3,672,213 to be collected annually from North Carolina $783,096 to be collected annually from South Carolina
Under wholesale contracts:	**$1,707,036** (contribution is not credited in future years)

- Assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections

  Rate of escalation in decommissioning costs = **0%**
  Rate of earnings on decommissioning funds = **3.25% (North Carolina)**
  2% (All Other Contributions)

  For wholesale contracts, the resultant assumed real rate of return of 2% is only applicable to funds accumulated from previous contributions associated with those contracts.

- Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v)

  None

- Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report

  None

- Material changes to trust agreements

  None

Attachment 4
Status of Financial Assurance Mechanism

Shearon Harris Nuclear Power Plant, Unit No. 1 **Docket No. 50-400 / License No. NPF-63**

- Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c)

  $354 million at expiration of current license, October 24, 2026

  Progress Energy Carolinas, Inc. share (83.83%) = $297 million

  $193 million estimated to be required from North Carolina
  $104 million estimated to be required from All Others

- Amount of decommissioning funds accumulated as of December 31, 2004

  $107,738,948

  $70,626,997 accumulated from North Carolina
  $37,111,951 accumulated from All Others

- Schedule of the annual amounts remaining to be collected

NRC Required Minimum:	**$3.33 million** $1.61 million required annually from North Carolina $1.72 million required annually from All Others
Allowed by North Carolina Utilities Commission and Public Service Commission of South Carolina:	**$5,216,661** $4,204,972 to be collected annually from North Carolina $1,011,689 to be collected annually from South Carolina
Under wholesale contracts:	**$954,497** (contribution is not credited in future years)

- Assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections

Rate of escalation in decommissioning costs =	**0%**
Rate of earnings on decommissioning funds =	**3.25% (North Carolina)** **2% (All Other Contributions)**

  For wholesale contracts, the resultant assumed real rate of return of 2% is only applicable to funds accumulated from previous contributions associated with those contracts.

- Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v)

  None

- Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report

  None

- Material changes to trust agreements

  None

Attachment 5
Status of Financial Assurance Mechanism

Crystal River Unit 3 Nuclear Generating Plant **Docket No. 50-302 / License No. DPR-72**

- Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c)

  $343,597,776 at expiration of current license, December 3, 2016

  Progress Energy Florida, Inc. share (91.7806%) = $315,356,101

- Amount of decommissioning funds accumulated as of December 31, 2004

  $315,356,101 **(This amount does not include additional funds collected for non-decommissioning activities, such as site restoration.)**

- Schedule of the annual amounts remaining to be collected

  None

- Assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections

  Rate of escalation in decommissioning costs = 0%
  Rate of earnings on decommissioning funds = 2%

- Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v)

  None

- Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report

  None

- Material changes to trust agreements

  None

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X]	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the fiscal year ended December 31, 2004
	OR
[ ]	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the transition period from ___________ to ___________

Commission File Number	Exact name of registrants as specified in their charters, state of incorporation, address of principal executive offices, and telephone number	I.R.S. Employer Identification Number
1-15929	**Progress Energy, Inc.** 410 South Wilmington Street Raleigh, North Carolina 27601-1748 Telephone: (919) 546-6111 State of Incorporation: North Carolina	56-2155481
1-3382	**Carolina Power & Light Company** **d/b/a Progress Energy Carolinas, Inc.** 410 South Wilmington Street Raleigh, North Carolina 27601-1748 Telephone: (919) 546-6111 State of Incorporation: North Carolina	56-0165465

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Progress Energy, Inc.:	
Common Stock (Without Par Value)	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Progress Energy, Inc.:	None
Carolina Power & Light Company:	$100 par value Preferred Stock, Cumulative $100 par value Serial Preferred Stock, Cumulative

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.
Yes __X__. No _____.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in PART III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether Progress Energy, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Act).
Yes __X__. No _____.

Indicate by check mark whether Carolina Power & Light Company is an accelerated filer (as defined in Rule 12b-2 of the Act).
Yes ______. No __X__.

As of June 30, 2004, the aggregate market value of the voting and non-voting common equity of Progress Energy, Inc. held by non-affiliates was $10,653,481,488. As of June 30, 2004, the aggregate market value of the common equity of Carolina Power & Light Company held by non-affiliates was $0. All of the common stock of Carolina Power & Light Company is owned by Progress Energy, Inc.

As of March 4, 2005, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy, Inc.	Common Stock (Without Par Value)	248,533,367
Carolina Power & Light Company	Common Stock (Without Par Value)	159,608,055

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Progress Energy and PEC definitive proxy statements dated March 31, 2005 are incorporated into PART III, ITEMS 10, 11, 12 , 13 and 14 hereof.

This combined Form 10-K is filed separately by two registrants: Progress Energy, Inc. (Progress Energy) and Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC). Information contained herein relating to either individual registrant is filed by such registrant solely on its own behalf.

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GLOSSARY OF TERMS

The following abbreviations or acronyms used in the text of this combined Form 10-K are defined below:

TERM	DEFINITION
401(k)	Progress Energy 401(k) Savings and Stock Ownership Plan
AFUDC	Allowance for funds used during construction
the Agreement	Stipulation and Settlement Agreement related to retail rate matters
AHI	Affordable housing investment
ARO	Asset retirement obligation
Bcf	Billion cubic feet
Broad River	Broad River LLC's Broad River Facility
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
Caronet	Caronet, Inc.
CCO	Competitive Commercial Operations business segment
CERCLA or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Code	Internal Revenue Code
Colona	Colona Synfuel Limited Partnership, LLLP
the Company	Progress Energy, Inc. and subsidiaries
CP&L	Carolina Power & Light Company
CP&L Energy	CP&L Energy, Inc.
CR3	Crystal River Unit No. 3
CVO	Contingent value obligation
DOE	United States Department of Energy
DWM	North Carolina Department of Environment and Natural Resources, Division of Waste Management
ETS	Engineering and Track-work
ECRC	Environmental Cost Recovery Clause
EITF	Emerging Issues Task Force
EMCs	Electric Membership Cooperatives
ENCNG	Eastern North Carolina Natural Gas Company, formerly referred to as EasternNC
EPA of 1992	Energy Policy Act of 1992
EPIK	EPIK Communications, Inc.
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environment and Protection
FERC	Federal Energy Regulatory Commission
FIN No. 45	Financial Accounting Standards Board (FASB) Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"
FIN No. 46R	FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51"
Florida Progress or FPC	Florida Progress Corporation
FPSC	Florida Public Service Commission
Fuels	Fuels business segment
Funding Corp.	Florida Progress Funding Corporation
GAAP	Accounting Principles Generally Accepted in the United States of America
Genco	Progress Genco Ventures LLC
Georgia Power	Georgia Power Company
Global	U.S. Global LLC
Harris Plant	Shearon Harris Nuclear Plant
the holding company	Progress Energy Corporate
Interpath	Interpath Communications, Inc.
IBEW	International Brotherhood of Electrical Workers
IRS	Internal Revenue Service
ISO	Independent System Operator

Jackson	Jackson Electric Membership Corporation
kV	Kilovolt
kVA	Kilovolt-ampere
LIBOR	London Inter Bank Offering Rate
LRS	Locomotive and Railcar Services
LSEs	Load-serving entities
MACT	Maximum Achievable Control Technology
MDC	Maximum Dependable Capability
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MGP	Manufactured Gas Plant
MW	Megawatt
MWh	Megawatt-hour
NC Clean Air	North Carolina Clean Smokestacks Act enacted in June 2002
NCNG	North Carolina Natural Gas Corporation
NCUC	North Carolina Utilities Commission
NDE	Nondestructive Examination
NEIL	Nuclear Electric Insurance Limited
NOx	Nitrogen Oxide
NOx SIP Call	EPA rule which requires 22 states including North and South Carolina to further reduce nitrogen oxide emissions.
NRC	United States Nuclear Regulatory Commission
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
O&M	Operations & Maintenance Expense
Odyssey	Odyssey Telecorp, Inc.
OPEB	Postretirement benefits other than pensions
P11	Intercession Unit P11
PCH	Progress Capital Holdings, Inc.
PEC	Progress Energy Carolinas, Inc.
PEC Electric	PEC Electric business segment made up of the utility operations and excludes operations of nonregulated subsidiaries
PEF	Progress Energy Florida
PESC	Progress Energy Service Company, LLC
PFA	IRS Prefiling Agreement
the Plan	Revenue Sharing Incentive Plan
PLR	Private Letter Ruling
Power Agency	North Carolina Eastern Municipal Power Agency
Preferred Securities	FPC-obligated mandatorily redeemable preferred securities of FPC Capital I
Progress Energy	Progress Energy, Inc.
Progress Fuels	Progress Fuels Corporation, formerly Electric Fuels Corporation
Progress Rail	Progress Rail Services Corporation
Progress Ventures	Business unit of Progress Energy primarily made up of nonregulated energy generation and marketing activities, as well as gas, coal and synthetic fuel operations
PRP	Potentially responsible party, as defined in CERCLA
PSSP	Performance Share Sub-Plan
PTC	Progress Telecommunications Corporation
PT LLC	Progress Telecom, LLC
PUHCA	Public Utility Holding Company Act of 1935, as amended
PURPA	Public Utilities Regulatory Policies Act of 1978
PVI	Progress Energy Ventures, Inc. (formerly referred to as CPL Energy Ventures, Inc.)
PWR	Pressurized water reactor
QF	Qualifying facility
Rail Services	Rail Services business segment
RCA	Revolving credit agreement
Rockport	Indiana Michigan Power Company's Rockport Unit No. 2
Robinson	PEC's Robinson Nuclear Plant
ROE	Return on Equity
RSA	Restricted Stock Awards program
RTO	Regional Transmission Organization

SCPSC	Public Service Commission of South Carolina
SEC	U.S. Securities and Exchange Commission
Section 29	Section 29 of the Internal Revenue Service Code
(See Note/s "#")	For all Sections, except the Carolina Power & Light Company Financial Statements in Part II, Item 8, this is a reference to the Notes in the Progress Energy Consolidated Financial Statements in Part II, Item 8
Service Company	Progress Energy Service Company, LLC
SFAS	Statement of Financial Accounting Standards
SFAS No. 5	Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies"
SFAS No. 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS No. 87	Statement of Financial Accounting Standards No. 87, "Employers' Accounting for Pensions"
SFAS No. 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes"
SFAS No. 121	Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of"
SFAS No. 123	Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation"
SFAS No. 123R	Statement of Financial Accounting Standards No. 123R, "Accounting for Stock-Based Compensation"
SFAS No. 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative and Hedging Activities"
SFAS No. 138	Statement of Financial Accounting Standards No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133"
SFAS No. 142	Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets"
SFAS No. 143	Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations"
SFAS No. 144	Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS No. 148	Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – An Amendment of FASB Statement No. 123"
SFAS No. 150	Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"
SMD NOPR	Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission and Standard Market Design
SO_2	Sulfur dioxide
SRS	Strategic Resource Solutions Corp.
Tax Agreement	Intercompany Income Tax Allocation Agreement
the Trust	FPC Capital I
Winchester Energy	Winchester Energy Company, Ltd. (formerly Westchester Gas Company)
Winchester Production	Winchester Production Company, Ltd., an indirectly owned subsidiary of Progress Fuels Corporation

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

Certain matters discussed throughout this Form 10-K that are not historical facts are forward-looking and, accordingly, involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

In addition, examples of forward-looking statements discussed in this Form 10-K include 1) PART II, ITEM 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" including, but not limited to, statements under the following headings: a) "Results of Operations" about trends and uncertainties; b) "Liquidity and Capital Resources" about operating cash flows, estimated capital requirements through the year 2007 and future financing plans; c) "Strategy" about Progress Energy, Inc.'s, strategy; and d) "Other Matters" about the effects of new environmental regulations, nuclear decommissioning costs and the effect of electric utility industry restructuring; and 2) statements made in the "Risk Factors" sections.

Any forward-looking statement is based on information current as of the date of this report and speaks only as of the date on which such statement is made, and neither Progress Energy, Inc., (the Company) nor Progress Energy Carolinas (PEC) undertakes any obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex government laws and regulations, including those relating to the environment; deregulation or restructuring in the electric industry that may result in increased competition and unrecovered (stranded) costs; the ability of the Company to implement its cost management initiatives as planned; the uncertainty regarding the timing, creation and structure of regional transmission organizations; weather conditions that directly influence the demand for electricity; the Company's ability to recover through the regulatory process, and the timing of such recovery of, the costs associated with the four hurricanes that impacted our service territory in 2004 or other future significant weather events; recurring seasonal fluctuations in demand for electricity; fluctuations in the price of energy commodities and purchased power; economic fluctuations and the corresponding impact on the Company and its subsidiaries' commercial and industrial customers; the ability of the Company's subsidiaries to pay upstream dividends or distributions to it; the impact on the facilities and the businesses of the Company from a terrorist attack; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the ability to successfully access capital markets on favorable terms; the impact on the Company's financial condition and ability to meet its cash and other financial obligations in the event its credit ratings are downgraded below investment grade; the impact that increases in leverage may have on the Company; the ability of the Company to maintain its current credit ratings; the impact of derivative contracts used in the normal course of business by the Company; investment performance of pension and benefit plans; the Company's ability to control costs, including pension and benefit expense, and achieve its cost management targets for 2007; the availability and use of Internal Revenue Code Section 29 (Section 29) tax credits by synthetic fuel producers and the Company's continued ability to use Section 29 tax credits related to its coal and synthetic fuel businesses; the impact to the Company's financial condition and performance in the event it is determined the Company is not entitled to previously taken Section 29 tax credits; the impact of future accounting pronouncements regarding uncertain tax positions; the outcome of PEF's rate proceeding in 2005 regarding its future base rates; the Company's ability to manage the risks involved with the operation of its nonregulated plants, including dependence on third parties and related counter-party risks, and a lack of operating history; the Company's ability to manage the risks associated with its energy marketing operations; the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements; and unanticipated changes in operating expenses and capital expenditures. Many of these risks similarly impact the Company's subsidiaries.

These and other risk factors are detailed from time to time in the Company's and PEC's filings with the United States Securities and Exchange Commission (SEC). Many, but not all, of the factors that may impact actual results are discussed in the "Risk Factors" sections of this report. You should carefully read the "Risk Factors" sections of this report. All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond the control of Progress Energy and PEC. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can it assess the effect of each such factor on Progress Energy and PEC.

PART I

ITEM 1. BUSINESS

GENERAL

COMPANY

Progress Energy, Inc. (Progress Energy or the Company, which includes consolidated subsidiaries unless otherwise indicated) is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA) and is an integrated energy company located principally in the southeast region of the United States. The Company is subject to the regulatory provisions of PUHCA. Progress Energy was incorporated on August 19, 1999. The Company was initially formed as CP&L Energy, Inc. (CP&L Energy), which became the holding company for Carolina Power & Light Company (CP&L) on June 19, 2000. All shares of common stock of CP&L were exchanged for an equal number of shares of CP&L Energy common stock.

Effective January 1, 2003, CP&L, Florida Power Corporation and Progress Ventures, Inc., (PVI) began doing business under the names Progress Energy Carolinas, Inc. (PEC), Progress Energy Florida, Inc. (PEF) and Progress Energy Ventures, Inc. (PVI), respectively. The legal names of these entities have not changed and there was no restructuring of any kind related to the name change.

Through its wholly owned regulated subsidiaries, PEC and PEF, Progress Energy is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. The Progress Ventures business unit consists of the Fuels business segment (Fuels) and Competitive Commercial Operations (CCO) operating segments. Progress Energy's legal structure is not currently aligned with the functional management and financial reporting of the Progress Ventures business unit. Whether, and when, the legal and functional structures will converge depends upon legislative and regulatory action, which cannot currently be anticipated. Through its Competitive Commercial Operations (CCO) business segment, Progress Energy is involved in nonregulated electricity generation operations. Through its Fuels business segment (Fuels), Progress Energy is involved in natural gas drilling and production, coal terminal services, coal mining, synthetic fuel production, fuel transportation and delivery. Both CCO and Fuels are involved in limited energy and commodity economic hedging activities. Through its Rail Services business segment (Rail Services), Progress Energy engages in various rail and railcar-related services. In February 2005, Progress Energy signed a definitive agreement to sell its Progress Rail subsidiary for a sales price of $405 million (See Note 24). The Corporate and Other Businesses segment primarily includes Service Company activities, miscellaneous nonregulated activities and holding company operations. For information regarding the revenues, income and assets attributable to the Company's business segments, See Note 20 to the Progress Energy Consolidated Financial Statements in PART II, ITEM 8.

The Company has approximately 24,000 megawatts (MW) of electric generation capacity and serves approximately 2.9 million retail electric customers in portions of North Carolina, South Carolina and Florida and also serves other load-serving entities. PEC's and PEF's customer base and demand cycles are complementary. Historically, PEC normally has a summer peaking demand, while PEF normally has a winter peaking demand. In addition, PEC's greater proportion of commercial and industrial customers, combined with PEF's greater proportion of residential customers, creates a balanced customer base. The Company is dedicated to expanding the Company's electric generation capacity and delivering reliable, competitively priced energy.

Progress Energy revenues for the year ended December 31, 2004, were $9.8 billion and assets at year-end were $26.0 billion. Its principal executive offices are located at 410 South Wilmington Street, Raleigh, North Carolina 27601, telephone number (919) 546-6111. The Progress Energy home page on the Internet is located at http://www.progress-energy.com, the contents of which are not and shall not be deemed a part of this document or any other U.S. Securities and Exchange Commission (SEC) filing. The Company makes available free of charge on its Web site its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC.

SIGNIFICANT DEVELOPMENTS

Sale of Natural Gas Assets

In December 2004, the Company sold certain gas-producing properties and related assets owned by Winchester Production Company, Ltd. (Winchester Production), an indirectly owned subsidiary of Progress Fuels Corporation (Progress Fuels), which is included in the Fuels segment. Net proceeds of approximately $251 million were used to reduce debt (See Note 4A).

2004 Hurricanes

Hurricanes Charley, Frances, Ivan and Jeanne struck significant portions of the Company's service territories during the third quarter of 2004, significantly impacting PEF's territory. As of December 31, 2004, restoration of the Company's systems from hurricane related damage was estimated at $398 million (See Note 3).

Divestiture of Synthetic Fuel Partnership Interests

In June 2004, the Company, through its subsidiary Progress Fuels, sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, 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 (See Note 4B).

Railcar Ltd., Divestiture

In March 2003, the Company signed a letter of intent to sell the majority of Railcar Ltd. assets to The Andersons, Inc. The asset purchase agreement was signed in November 2003, and the transaction closed on February 12, 2004. Net proceeds of approximately $75 million were used to reduce debt (See Note 4C).

Progress Telecommunications Corporation Business Combination

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. 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 holds a 55% ownership interest in and is the parent of PT LLC (See Note 5A).

Mesa Hydrocarbons, Inc. Divestiture

In October 2003, the Company sold certain gas-producing properties owned by Mesa Hydrocarbons, LLC, a wholly owned subsidiary of Progress Fuels. Net proceeds of approximately $97 million were used to reduce debt (See Note 4D).

NCNG Divestiture

In September 2003, the Company completed the sale of North Carolina Natural Gas Corporation (NCNG) and the Company's equity investment in Eastern North Carolina Natural Gas Company (ENCNG) to Piedmont Natural Gas Company, Inc. As a result of this action, the operating results of NCNG were reclassified to discontinued operations for all reportable periods. Net proceeds from the sale of NCNG and ENCNG of approximately $443 million were used to reduce debt (See Note 4E).

Acquisition of Natural Gas Reserves

During 2003, Progress Fuels entered into several independent transactions to acquire approximately 200 natural gas-producing wells with proven reserves of approximately 190 billion cubic feet (Bcf) from Republic Energy, Inc. and three other privately owned companies, all headquartered in Texas. The total cash purchase price for the transactions was approximately $168 million (See Note 5B).

Wholesale Energy Contract Acquisition

In May 2003, Progress 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), for $188 million (See Note 5C).

Westchester Acquisition

In April 2002, Progress Fuels acquired 100% of Westchester Gas Company (Westchester). During 2004, the name of the company was changed to Winchester Energy Co. Ltd., (Winchester Energy). The acquisition included approximately 215 natural gas-producing wells, 52 miles of intrastate gas pipeline and 170 miles of gas-gathering systems. The aggregate purchase price was approximately $153 million (See Note 5D).

Generation Acquisition

In February 2002, PVI acquired 100% of two electric generating projects in Georgia from LG&E Energy Corp., a subsidiary of Powergen plc. for a total cash purchase price of approximately $348 million. The transaction included tolling agreements and two power purchase agreements with LG&E Energy Marketing, Inc. (See Note 5E).

Florida Progress Acquisition

On November 30, 2000, the Company completed its acquisition of Florida Progress Corporation (FPC), a diversified, exempt electric utility holding company, for an aggregate purchase price of approximately $5.4 billion. The Company paid cash consideration of approximately $3.5 billion and issued 46.5 million shares of common stock valued at approximately $1.9 billion. In addition, the Company issued 98.6 million contingent value obligations (CVOs) valued at approximately $49 million.

The FPC acquisition was accounted for using the purchase method of accounting and, accordingly, the results of operations for FPC have been included in the Company's Consolidated Financial Statements since the date of acquisition.

COMPETITION

GENERAL

In recent years, the electric utility industry has experienced a substantial increase in competition at the wholesale level, caused by changes in federal law and regulatory policy. Several states have also decided to restructure aspects of retail electric service. The issue of retail restructuring and competition is being reviewed by a number of states, and bills have been introduced in past sessions of Congress that sought to introduce such restructuring in all states.

The 108th Congress spent much of 2004 working on a comprehensive energy bill. While that legislation passed the House, the Senate failed to pass the legislation in 2004. The Company expects that there will be an effort to resurrect the legislation in 2005. The legislation would have further clarified the Federal Energy Regulatory Commission's (FERC) role with respect to Standard Market Design and mandatory Regional Transmission Organizations (RTOs) and would have repealed PUHCA. The Company cannot predict the outcome of this matter.

As a result of the Public Utilities Regulatory Policies Act of 1978 (PURPA) and the Energy Policy Act of 1992 (EPA of 1992), competition in the wholesale electricity market has greatly increased, especially from nonutility generators of electricity. In 1996, the FERC issued new rules on transmission service to facilitate competition in the wholesale market on a nationwide basis. The rules give greater flexibility and more choices to wholesale power customers.

To date, many states have adopted legislation that would give retail customers the right to choose their electricity provider (retail choice), and most other states have, in some form, considered the issue. There is currently no proposed legislation in North Carolina, South Carolina or Florida that would introduce retail choice.

Since passage of the EPA of 1992, competition in the wholesale electric utility industry has significantly increased due to a greater participation by traditional electricity suppliers, wholesale power marketers and brokers and due to the trading of energy futures contracts on various commodities exchanges. This increased competition could affect

PEC and PEF's load forecasts, plans for power supply and wholesale energy sales and related revenues. The impact could vary depending on the extent to which additional generation is built to compete in the wholesale market, new opportunities are created for PEC and PEF to expand their wholesale load, or current wholesale customers elect to purchase from other suppliers after existing contracts expire.

An issue encompassed by industry restructuring is the recovery of "stranded costs." Stranded costs primarily include the generation assets of utilities whose value in a competitive marketplace would be less than their current book value, as well as above-market purchased power commitments to qualifying facilities (QFs). Thus far, all states that have passed restructuring legislation have provided for the opportunity to recover a substantial portion of stranded costs. Assessing the amount of stranded costs for a utility requires various assumptions about future market conditions, including the future price of electricity.

In November 2003, the FERC adopted new standards of conduct that apply uniformly to interstate natural gas pipelines and public utilities. These standards have been clarified and supplemented by subsequent FERC orders. The new standards of conduct govern the relationship between transmission providers and their energy affiliates in a manner that prevents excessive market power and preferential treatment. Each utility was required to submit a plan and schedule for compliance with the new rules by February 2004. PEC and PEF have complied in all material respects with all of the requirements associated with these standards and FERC orders.

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. Management is unable to predict the outcome of these actions by the FERC or their effect on future results of operations and cash flows. PEF does not have market-based rate authority for wholesale sales in peninsular Florida. Given the difficulty PEC believes it would experience in passing one of the interim screens, on August 12, 2004, PEC notified the FERC that it would revise its Market-based Rate tariff to restrict it to sales outside PEC's control area and file a new cost-based tariff for sales within PEC's control area that incorporates the FERC's default cost-based rate methodologies for sales of one year or less. PEC anticipates making this filing the first quarter of 2005.

On December 23, 2004, PEF advised the FERC that PEF only has market-based rate authority in Southern Company's control area in Georgia. PEF also advised the FERC that PEF filed market power studies in 2003 demonstrating that it does not have market power in that market and that because nothing has changed since that study was performed, PEF should not have to perform the new tests.

Although the Company cannot predict the ultimate outcome of these changes, the Company does not anticipate that the current operations of PEC or PEF would be impacted materially if they were unable to sell power at market-based rates in their respective control areas.

See PART I, ITEM 1, "Competition" of Electric-PEC and Electric-PEF for discussions of franchises as they relate to PEC and PEF.

See PART I, ITEM 1, "Competition," under Electric-PEC, Electric-PEF and Other for further discussion of competitive developments within these segments.

PUHCA

As a result of the acquisition of FPC, Progress Energy is now a registered holding company subject to regulation by the SEC under PUHCA. Therefore, Progress Energy and its subsidiaries are subject to the regulatory provisions of PUHCA, including provisions relating to the issuance of securities, sales, acquisitions of securities and utility assets, and services performed by Progress Energy Service Company, LLC.

While various proposals, including the 2004 energy bill, have been introduced in Congress regarding PUHCA, the prospects for legislative reform or repeal are uncertain at this time.

REGULATORY MATTERS

GENERAL

PEC is subject to regulation in North Carolina by the North Carolina Utilities Commission (NCUC), and in South Carolina by the Public Service Commission of South Carolina (SCPSC) and PEF is subject to regulation in Florida by the Florida Public Service Commission (FPSC) with respect to, among other things, rates and service for electric energy sold at retail, retail service territory cost recovery of unusual or unexpected expense, such as severe storm costs, and issuances of securities. PEC and PEF are also subject to regulation by the United States Nuclear Regulatory Commission (NRC). In addition, PEC and PEF are subject to regulation by the FERC with respect to transmission and sales of wholesale power, accounting and certain other matters. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service, including a reasonable rate of return on its equity. Increased competition as a result of industry restructuring may affect the ratemaking process.

NUCLEAR MATTERS

GENERAL

PEC owns and operates four nuclear generating units and PEF owns and operates one nuclear generating unit regulated by the NRC under the Atomic Energy Act of 1954 and the Energy Reorganization Act of 1974. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit, or some combination of these, depending upon its assessment of the severity of the situation, until compliance is achieved. Nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs and certain other modifications.

The nuclear power industry faces uncertainties with respect to the cost and long-term availability of sites for disposal of spent nuclear fuel and other radioactive waste, compliance with changing regulatory requirements, nuclear plant operations, increased capital outlays for modifications, the technological and financial aspects of decommissioning plants at the end of their licensed lives and requirements relating to nuclear insurance.

On April 19, 2004, the NRC announced that it has renewed the operating license for PEC's Robinson Nuclear Plant (Robinson) for an additional 20 years through July 2030. The original operating license of 40 years was set to expire in 2010. NRC operating licenses held by PEC currently expire in December 2014 and September 2016 for Brunswick Units 2 and 1, respectively. An application to extend these licenses 20 years was submitted in October 2004. The NRC operating license held by PEC for the Shearon Harris Nuclear Plant (Harris Plant) currently expires in October 2026. An application to extend this license 20 years is expected to be submitted in the fourth quarter of 2006.

The NRC operating license held by PEF for Crystal River Unit No. 3 (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.

A condition of the operating license for each unit requires an approved plan for decontamination and decommissioning.

On February 27, 2004, PEC requested to have its license for the Independent Spent Fuel Storage Installation at the Robinson Plant extended by 20 years with an exemption request for an additional 20-year extension. Its current license is due to expire in August 2006. PEC expects to receive this extension including the exemption.

PRESSURIZED WATER REACTORS

In 2002, the NRC sent a bulletin to companies that hold licenses for pressurized water reactors (PWRs) requiring information on the structural integrity of the reactor vessel head and a basis for concluding that the vessel head will continue to perform its function as a coolant pressure boundary. Inspections of the vessel heads at the Company's PWR plants had been performed during previous outages. At the Robinson and Harris Plants, inspections were completed in 2001, and there was no degradation of the reactor vessel heads. The Company's Brunswick Plant has a different design and is not affected by the issue. Inspection of the vessel head at CR3 was performed during a previous outage, and no degradation of the reactor vessel head was identified.

In 2002, the NRC issued an additional bulletin dealing with head leakage due to cracks near the control rod nozzles, asking licensees to commit to high inspection standards to ensure the more susceptible plants have no cracks. The Robinson Plant is in this category and had a refueling outage in 2002. The Company completed a series of examinations in 2002 of the entire reactor pressure vessel head and found no indications of control rod drive mechanism cracking and no corrosion of the head itself. During the outage, a walkdown of the reactor coolant pressure boundary was also completed, and no corrosion was found. The Robinson reactor head was re-inspected during its 2004 outage, and no indication of control rod drive mechanism cracking or corrosion of the head was observed. The head is scheduled for replacement in 2005. The Harris Plant is ranked in the lowest susceptibility classification. PEF replaced the vessel head at CR3 during its regularly scheduled refueling outage in 2003.

In 2003, the NRC issued an order requiring specific inspections of the reactor pressure vessel head and associated penetration nozzles at PWRs. The Company responded, stating that it intended to comply with the provisions of the order. The NRC also issued a bulletin requesting PWR licensees to address inspection plans for reactor pressure vessel lower head penetrations. The Company completed a bare metal visual inspection of the vessel bottom at Robinson during its 2004 outage and at Harris and CR3 during their 2003 outages and found no signs of corrosion or leakage at any unit. The Company plans to do additional, more detailed inspections as part of the next scheduled 10-year in-service inspections.

In February 2004, the NRC issued a revised order for inspection requirements for reactor pressure vessel heads at PWRs. The Company has reviewed the required inspection frequencies and has incorporated them into long-range plans. The Harris Plant will complete the required nonvisual nondestructive examination (NDE) inspection prior to February 2008. Both CR3 and Robinson will be required to inspect their new heads within seven years or four refueling outages after replacement. CR3 plans to inspect its new head prior to the end of 2009, and Robinson will need to inspect its new head prior to the end of 2012.

SECURITY

The NRC has issued various orders since September 2001 with regard to security at nuclear plants. These orders include additional restrictions on access, increased security measures at nuclear facilities and closer coordination with the Company's partners in intelligence, military, law enforcement and emergency response at the federal, state and local levels. The Company completed the requirements as outlined in the orders by the committed dates. As the NRC, other governmental entities and the industry continue to consider security issues, it is possible that more extensive security plans could be required.

SPENT FUEL AND OTHER HIGH-LEVEL RADIOACTIVE WASTE

The Nuclear Waste Policy Act of 1982 (Nuclear Waste Act) provides the framework for development by the federal government of interim storage and permanent disposal facilities for high-level radioactive waste materials. The Nuclear Waste Act promotes increased usage of interim storage of spent nuclear fuel at existing nuclear plants. The Company will continue to maximize the use of spent fuel storage capability within its own facilities for as long as feasible.

With certain modifications and additional approval by the NRC, including the installation of onsite dry storage facilities at Robinson (2005) and Brunswick (2010), 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 current 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, Crystal River Unit No. 3 (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.

See Note 23E and Note 18D to the PGN and PEC Consolidated Financial Statements, respectively, for a discussion of the Company's contract with the U.S. Department of Energy (DOE) for spent nuclear waste.

DECOMMISSIONING

In PEC's and PEF's 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 jurisdiction, the provisions for nuclear decommissioning costs are approved by the FERC. See Note 6D for a discussion of PEC and PEF's nuclear decommissioning costs.

ENVIRONMENTAL

In the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes and other environmental matters, the Company is subject to regulation by various federal, state and local authorities. The Company considers itself to be in substantial compliance with those environmental regulations currently applicable to its business and operations and believes it has all necessary permits to conduct such operations. Environmental laws and regulations constantly evolve and the ultimate costs of compliance cannot always be accurately estimated. The estimated capital costs associated with compliance with pollution control laws and regulations at the Company's existing fossil facilities that the Company expects to incur from 2005 through 2007 are included in the "Capital Expenditures" discussion for Progress Energy under PART II, ITEM 7, "Liquidity and Capital Resources."

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North and South Carolina, have similar types of legislation. Both electric utilities, Progress Fuels and Progress Rail Services Corporation (Progress Rail) are periodically notified by regulators such as the EPA and various state agencies of their involvement or potential involvement in sites that may require investigation and/or remediation.

There are presently several sites, including manufactured gas plant (MGP) sites, with respect to which the Company has been notified by the EPA, the State of North Carolina or the State of Florida of its potential liability, as a potentially responsible party (PRP). Although the Company's subsidiaries may incur costs at the sites about which they have been notified, based upon the current status of these sites, the Company cannot determine the total costs that may be incurred in connection with all sites at this time. See Note 22 for a discussion of the Company's environmental matters.

EMPLOYEES

As of February 28, 2005, Progress Energy and its subsidiaries employed approximately 15,700 full-time employees. Of this total, approximately 2,400 employees at PEF are represented by the International Brotherhood of Electrical Workers (IBEW). The three-year labor contract with IBEW expires in December 2005.

The Company and some of its subsidiaries have a noncontributory defined benefit retirement (pension) plan for substantially all full-time employees and an employee stock purchase plan among other employee benefits. The Company and some of its subsidiaries also provide contributory postretirement benefits, including certain health care and life insurance benefits, for substantially all retired employees.

On February 28, 2005, as part of a previously announced cost management initiative, the executive officers of the Company approved a workforce restructuring. The restructuring will result in a reduction of approximately 450 positions and is expected to be completed in September of 2005. In addition to the workforce restructuring, the cost management initiative includes a voluntary enhanced retirement program. See Note 24 for more information.

As of February 28, 2005, PEC employed approximately 5,100 full-time employees.

ELECTRIC – PEC

GENERAL

PEC is a public service corporation formed under the laws of North Carolina in 1926 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North and South Carolina. At December 31, 2004, PEC had a total summer generating capacity (including jointly owned capacity) of approximately 12,482 MW.

PEC distributes and sells electricity in 56 of the 100 counties in North Carolina and 14 counties in northeastern South Carolina. The service territory covers approximately 34,000 square miles, including a substantial portion of the coastal plain of North Carolina extending to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in northeastern South Carolina and an area in western North Carolina in and around the city of Asheville. At December 31, 2004, PEC was providing electric services, retail and wholesale, to approximately 1.4 million customers. Major wholesale power sales customers include North Carolina Eastern Municipal Power Agency (Power Agency) and North Carolina Electric Membership Corporation. PEC is subject to the rules and regulations of the FERC, the NCUC, the SCPSC and the NRC. No single customer accounts for more than 10% of PEC's revenues.

BILLED ELECTRIC REVENUES

PEC's electric revenues billed by customer class, for the last three years, are shown as a percentage of total PEC electric revenues in the table below:

BILLED ELECTRIC REVENUES

Revenue Class	2004	2003	2002
Residential	**38%**	36%	36%
Commercial	**25%**	24%	24%
Industrial	**19%**	18%	19%
Wholesale	**16%**	20%	19%
Other retail	**2%**	2%	2%

Major industries in PEC's service area include textiles, chemicals, metals, paper, food, rubber and plastics, wood products and electronic machinery and equipment.

FUEL AND PURCHASED POWER

Sources of Generation

PEC's consumption of various types of fuel depends on several factors, the most important of which are the demand for electricity by PEC's customers, the availability of various generating units, the availability and cost of fuel and the requirements of federal and state regulatory agencies. PEC's total system generation (including jointly owned capacity) by primary energy source, along with purchased power for the last three years is presented in the following table:

ENERGY MIX PERCENTAGES

	2004	2003	2002
Coal	**47%**	46%	46%
Nuclear	**43%**	44%	42%
Purchased power	**6%**	7%	8%
Oil/Gas	**3%**	2%	3%
Hydro	**1%**	1%	1%

PEC is generally permitted to pass the cost of fuel and purchased power to its customers through fuel adjustment clauses. The future prices for and availability of various fuels discussed in this report cannot be predicted with complete certainty. See "Commodity Price Risk" under Item 7A, QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and "Risk Factors." However, PEC believes that its fuel supply contracts, as described below, will be adequate to meet its fuel supply needs.

PEC's average fuel costs per million British thermal units (Btu) for the last three years were as follows:

AVERAGE FUEL COST
(per million Btu)

	2004	2003	2002
Coal	**$ 2.17**	$ 2.00	$ 1.93
Nuclear	**0.42**	0.43	0.43
Oil	**6.78**	6.69	5.48
Gas	**8.29**	8.32	5.31
Hydro	**–**	–	–
Weighted-average	**1.57**	1.43	1.38

Changes in the unit price for coal, oil and gas are due to market conditions. Since these costs are primarily recovered through recovery clauses established by regulators, fluctuations do not materially affect net income.

Coal

PEC anticipates a requirement of approximately 12.4 million to 13.0 million tons of coal in 2005. Almost all of the coal will be supplied from Appalachian coal sources in the United States and is primarily delivered by rail.

For 2005, PEC has short-term, intermediate and long-term agreements from various sources for approximately 102% of its burn requirements of its coal units. All of these contracts are at fixed prices adjusted annually. The contracts have expiration dates ranging from 2005 to 2009. PEC will continue to sign contracts of various lengths, terms and quality to meet its expected burn requirements. All the coal to be purchased for PEC is considered to be low sulfur coal by industry standards.

Nuclear

Nuclear fuel is processed through four distinct stages. Stages I and II involve the mining and milling of the natural uranium ore to produce a uranium oxide concentrate and the conversion of this concentrate into uranium hexafluoride. Stages III and IV entail the enrichment of the uranium hexafluoride and the fabrication of the enriched uranium hexafluoride into usable fuel assemblies.

PEC has sufficient uranium, conversion, enrichment and fabrication contracts to meet its near-term nuclear fuel requirement needs. PEC's nuclear fuel contracts typically have terms ranging from five to ten years. For a discussion of PEC's plans with respect to spent fuel storage, see PART I, ITEM 1, "Nuclear Matters."

Hydroelectric

Hydroelectric power is electric energy generated by the force of falling water. PEC has three hydroelectric generating plants licensed by the FERC: Walters, Tillery and Blewett. PEC also owns the Marshall Plant, which has a license exemption. The total maximum dependable capacity for all four units is 218 MW. PEC is seeking to relicense its Tillery and Blewett Plants. These plants' licenses currently expire in April 2008. The Walters Plant license will expire in 2034.

Oil & Gas

Oil and natural gas supply for PEC's generation fleet is purchased under term and spot contracts from several suppliers. The cost of PEC's oil and gas is determined by market prices as reported in certain industry publications. PEC believes that it has access to an adequate supply of oil and gas for the reasonably foreseeable future. PEC's natural gas transportation is purchased under term firm transportation contracts with interstate pipelines. PEC also purchases capacity on a seasonal basis from numerous shippers for its peaking load requirements. PEC believes that existing contracts for oil are sufficient to cover its requirements if natural gas is unavailable during a normal winter period for PEC's combustion turbine and combined cycle fleet.

Purchased Power

PEC purchased approximately 4.0 million MWh, 4.5 million MWh and 5.2 million MWh of its system energy requirements during 2004, 2003 and 2002, respectively, and had available 1,498 MW, 1,810 MW and 1,737 MW of firm purchased capacity under contract at the time of peak load during 2004, 2003 and 2002, respectively. PEC may acquire additional purchased power capacity in the future to accommodate a portion of its system load needs.

COMPETITION

Electric Industry Restructuring

PEC continues to monitor developments that may occur toward a more competitive environment and actively participates in regulatory reform deliberations in North Carolina and South Carolina. PEC expects that both the North Carolina and South Carolina General Assemblies will continue to monitor the experiences of states that have implemented electric restructuring legislation.

Regional Transmission Organizations

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 a GridSouth RTO. In July 2001, the FERC issued an order provisionally approving GridSouth. However, in July 2001, the FERC issued orders recommending that companies in the southeast engage in a mediation to develop a plan for a single RTO for the Southeast. PEC participated in the mediation. On December 22, 2004, the FERC, citing superseding events, voted to close a portion of the GridSouth docket. The GridSouth Companies asked the FERC for further clarification as to the portions of the GridSouth docket it intended to address. On March 2, 2005, the FERC affirmed that it only intended to close the mediation portion of the GridSouth docket.

See Note 8D for additional discussion of current developments of GridSouth RTO.

Franchises

PEC has nonexclusive franchises with varying expiration dates in most of the municipalities in which it distributes electric energy in North Carolina and South Carolina. The general effect of these franchises is to provide for the manner in which PEC occupies rights-of-way in incorporated areas of municipalities for the purpose of constructing, operating and maintaining an energy transmission and distribution system. Of these 239 franchises, 194 have expiration dates ranging from 2008 to 2061 and 45 of these have no specific expiration dates. All but 13 of the 194 franchises with expiration dates have a term of sixty years. The exceptions include three franchises with terms of ten years, one with a term of twenty years, six with terms of thirty years, two with terms of forty years and one with a term of fifty years. PEC also serves within a number of municipalities and in all of its unincorporated areas without franchise agreements.

Wholesale Competition

See PART I, ITEM 1, "General," under Competition for a discussion of wholesale competition.

Stranded Costs

See PART I, ITEM 1, "General," under Competition for a discussion of stranded costs.

REGULATORY MATTERS

General

PEC is subject to the jurisdiction of the NCUC and SCPSC with respect to, among other things, rates and service for electric energy sold at retail, retail service territory and issuances of securities. In addition, PEC is subject to regulation by the FERC with respect to transmission and sales of wholesale power, accounting and certain other matters. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus a reasonable rate of return on its equity. Increased competition as a result of industry restructuring may affect the ratemaking process.

Retail Rate Matters

The NCUC and the SCPSC authorize retail "base rates" that are designed to provide a utility with the opportunity to earn a specific rate of return on its "rate base," or investment in utility plant. These rates are intended to cover all reasonable and prudent expenses of utility operations and to provide investors with a fair rate of return. In PEC's most recent rate cases in 1988, the NCUC and the SCPSC each authorized a return on equity of 12.75% for PEC.

The Clean Smokestacks Act enacted in North Carolina in 2002 (NC Clean Air) freezes PEC's base retail rates for five years unless there are extraordinary events beyond the control of PEC, in which case PEC can petition for a rate increase. See Note 22 and Note 8B to the PGN and PEC Consolidated Financial Statements, respectively, for further discussion of PEC's rate freeze.

See Note 8B and Note 6B to the PGN and PEC Consolidated Financial Statements, respectively, for further discussion of PEC's retail rate developments during 2004.

Wholesale Rate Matters

PEC is subject to regulation by the FERC with respect to rates for transmission and sale of electric energy at wholesale, the interconnection of facilities in interstate commerce (other than interconnections for use in the event of certain emergency situations), the licensing and operation of hydroelectric projects and, to the extent the FERC determines, accounting policies and practices. PEC and its wholesale customers last agreed to a general increase in wholesale rates in 1988; however, wholesale rates have been adjusted since that time through contractual negotiations.

See PART I, ITEM 1, "General," under Competition for further discussion of FERC screens for assessing generation market power.

Fuel Cost Recovery

PEC's operating costs not covered by the utility's base rates include fuel and purchased power. Each state commission allows electric utilities to recover a certain portion of these costs through various cost recovery clauses, to the extent the respective commission determines in an annual hearing that such costs are prudent. Costs recovered by PEC, by state, are as follows:

- *North Carolina* – fuel costs and the fuel portion of purchased power
- *South Carolina* – fuel costs, certain purchased power costs, and emission allowance expense

Each state commission's determination results in the addition of a rider to a utility's base rates to reflect the approval of these costs and to reflect any past over- or under-recovery. Due to the regulatory treatment of these costs and the method allowed for recovery, changes from year to year have no material impact on operating results.

NUCLEAR MATTERS

PEC is implementing power uprate projects at its nuclear facilities to increase electrical generation output. A power uprate was completed at the Harris Plant during 2001 and at the Robinson Nuclear Plant in 2002. At the Brunswick Plant, Unit 1 increased its capacity by 52 MW in 2002 and by 66 MW in 2004. Brunswick Unit 2 increased its capacity by 89 MW in 2003, and an additional increase is planned for 2005. The total increased generation from all these projects is estimated to be approximately 300 MW. See PART I, ITEM 1, "Nuclear Matters," for further discussion of these and other nuclear matters.

ENVIRONMENTAL MATTERS

In the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes and other environmental matters, PEC is subject to regulation by various federal, state and local authorities. PEC considers itself to be in substantial compliance with those environmental regulations currently applicable to its business and operations and believes it has all necessary permits to conduct such operations. Environmental laws and regulations constantly evolve, and the ultimate costs of compliance cannot always be accurately estimated. The estimated capital costs associated with compliance with pollution control laws and regulations at the PEC's existing fossil facilities that it expects to incur from 2005 through 2007 are included in the "Capital Expenditures" discussion under PART II, ITEM 7, "Liquidity and Capital Resources."

The provisions of the Comprehensive Environmental Response, CERCLA, authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North and South Carolina, have similar types of legislation. There are presently nine former MGP sites and a number of other sites with respect to which PEC has been notified by the EPA or the State of North Carolina of its potential liability, as a PRP. Although PEC may incur costs at the sites about which it has been notified, based upon the current status of these sites, PEC cannot determine the total costs that may be incurred in connection with all sites at this time. See Notes 22 and 17 to the PGN and PEC Consolidated Financial Statements, respectively, for a discussion of PEC's environmental matters.

ELECTRIC – PEF

GENERAL

PEF, incorporated in Florida in 1899, is an operating public utility engaged in the generation, transmission, distribution and sale of electricity. At December 31, 2004, PEF had a total summer generating capacity (including jointly owned capacity) of approximately 8,544 MW.

PEF provided electric service during 2004 to an average of 1.5 million customers in west central Florida. Its service territory covers approximately 20,000 square miles and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 21 municipal and 9 rural electric cooperative systems. Major wholesale power sales customers include Seminole Electric Cooperative, Inc., Florida Power & Light Company, Tampa Electric Company and the City of Bartow. PEF is subject to the rules and regulations of the FERC, the FPSC and the NRC. No single customer accounts for more than 10% of PEF's revenues.

BILLED ELECTRIC REVENUES

PEF's electric revenues, billed by customer class for the last three years, are shown as a percentage of total PEF electric revenues in the table below:

BILLED ELECTRIC REVENUES

Revenue Class	2004	2003	2002
Residential	53%	55%	55%
Commercial	25%	24%	24%
Industrial	8%	7%	7%
Other retail	6%	6%	6%
Wholesale	8%	8%	8%

Important industries in PEF's territory include phosphate rock mining and processing, electronics design and manufacturing, and citrus and other food processing. Other important commercial activities are tourism, health care, construction and agriculture.

FUEL AND PURCHASED POWER

Sources of Generation

PEF's consumption of various types of fuel depends on several factors, the most important of which are the demand for electricity by PEF's customers, the availability of various generating units, the availability and cost of fuel and the requirements of federal and state regulatory agencies. PEF's total system generation (including jointly owned capacity) by primary energy source, along with purchased power for the last three years is presented in the following table:

ENERGY MIX PERCENTAGES

Fuel Type	2004	2003	2002
Coal [(a)]	**32%**	36%	33%
Oil	**16%**	16%	16%
Nuclear	**16%**	14%	15%
Gas	**16%**	13%	15%
Purchased Power	**20%**	21%	21%

(a) Amounts include synthetic fuel from unrelated third parties.

PEF is generally permitted to pass the cost of fuel and purchased power to its customers through fuel adjustment clauses. The future prices for and availability of various fuels discussed in this report cannot be predicted with complete certainty. See "Commodity Price Risk" under Item 7A, QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and "Risk Factors." However, PEF believes that its fuel supply contracts, as described below, will be adequate to meet its fuel supply needs.

PEF's average fuel costs per million Btu for the last three years were as follows:

AVERAGE FUEL COST
(per million Btu)

	2004	2003	2002
Coal [(a)]	**$ 2.30**	$ 2.42	$ 2.43
Oil	**4.67**	4.38	3.77
Nuclear	**0.49**	0.50	0.46
Gas	**6.41**	5.98	4.06
Weighted-average	**3.21**	3.07	2.60

(a) Amounts include synthetic fuel from unrelated third parties.

Changes in the unit price for coal, oil and gas are due to market conditions. Since these costs are primarily recovered through recovery clauses established by regulators, fluctuations do not materially affect net income.

Coal

PEF anticipates a combined requirement of approximately 6 million tons of coal in 2005. Approximately 70% of the coal is expected to be supplied from Appalachian coal sources in the United States and 30% supplied from coal sources in South America. Approximately 67% of the fuel is expected to be delivered by rail and the remainder by barge. All of this fuel is supplied by Progress Fuels, a subsidiary of Progress Energy, pursuant to contracts between PEF and Progress Fuels.

For 2005, Progress Fuels has medium-term and long-term contracts with various sources for approximately 115% of the burn requirements of PEF's coal units. Supply disruption caused by recent hurricanes has made it necessary to build inventories back to the traditional level of 45 days. These contracts have price adjustment provisions and have expiration dates ranging from 2005 to 2006. Progress Fuels will continue to sign contracts of various lengths, terms and quality to meet PEF's expected burn requirements. All the coal to be purchased for PEF is considered to be low sulfur coal by industry standards.

Oil and Gas

Oil and natural gas supply for PEF's generation fleet is purchased under term and spot contracts from several suppliers. The majority of the cost of PEF's oil and gas is determined by market prices as reported in certain industry publications. PEF believes that it has access to an adequate supply of oil and gas for the reasonably foreseeable future. PEF's natural gas transportation is purchased under term firm transportation contracts with interstate pipelines. PEF purchases capacity on a seasonal basis from numerous shippers and interstate pipelines to serve its peaking load requirements. PEF also uses interruptible transportation contracts on certain occasions when available. PEF believes that existing contracts for oil are sufficient to cover its requirements if natural gas is unavailable during certain time periods.

Nuclear

Nuclear fuel is processed through four distinct stages. Stages I and II involve the mining and milling of the natural uranium ore to produce a uranium oxide concentrate and the conversion of this concentrate into uranium hexafluoride. Stages III and IV entail the enrichment of the uranium hexafluoride and the fabrication of the enriched uranium hexafluoride into usable fuel assemblies.

PEF has sufficient uranium, conversion, enrichment and fabrication contracts to meet its near-term nuclear fuel requirements needs. PEF's nuclear fuel contracts typically have terms ranging from five to ten years. For a discussion of PEF's plans with respect to spent fuel storage, see PART I, ITEM I, "Nuclear Matters."

Purchased Power

PEF, along with other Florida utilities, buys and sells power in the wholesale market on a short-term and long-term basis. At December 31, 2004, PEF had a variety of purchase power agreements for the purchase of approximately 1,498 MW of firm power. These agreements include (1) long-term contracts for the purchase of about 484 MW of purchased power with other investor-owned utilities, including a contract with The Southern Company for approximately 414 MW, and (2) approximately 821 MW of capacity under contract with certain QFs. The capacity currently available from QFs represents about 9% of PEF's total installed system capacity.

COMPETITION

Electric Industry Restructuring

PEF continues to monitor developments toward a more competitive environment and actively participates in regulatory reform deliberations in Florida. Movement toward deregulation in this state has been affected by developments related to deregulation of the electric industry in other states.

In response to a legislative directive, the FPSC and the Florida Department of Environment and Protection (FDEP) submitted in February 2003 a joint report on renewable electric generating technologies for Florida. The report assessed the feasibility and potential magnitude of renewable electric capacity for Florida, and summarized the mechanisms other states have adopted to encourage renewable energy. The report did not contain any policy recommendations. The Company cannot anticipate when, or if, restructuring legislation will be enacted or if the Company would be able to support it in its final form.

Regional Transmission Organizations

As a result of Order 2000, PEF, Florida Power & Light Company and Tampa Electric Company (collectively, the Applicants) filed with the FERC in October 2000 an application for approval of a GridFlorida RTO. The GridFlorida proposal is pending before both the FERC and the FPSC. The FERC provisionally approved the structure and governance of GridFlorida. 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 currently scheduled to be presented at a FPSC workshop on May 25, 2005, with subsequent action by the FPSC to be thereafter determined. It is unknown when the FERC or the FPSC will take final action with regard to the status of GridFlorida or what the impact of further proceedings will have on the Company's earnings, revenues or pricing. See Note 8D for a discussion of current developments of GridFlorida RTO.

Franchises

PEF holds franchises with varying expiration dates in 108 of the municipalities in which it distributes electric energy. PEF also serves 13 other municipalities and in all its unincorporated areas without franchise agreements. The general purpose of these franchises is to provide for the manner in which PEF occupies rights-of-way in incorporated areas of municipalities for the purpose of constructing, operating and maintaining an energy transmission and distribution system.

Approximately 39% of PEF's total utility revenues for 2004 were from the incorporated areas of the 108 municipalities that had franchise ordinances during the year. Since 2000, PEF has renewed 34 expiring franchises and reached agreement on a franchise with a city that did not previously have a franchise. Franchises with five municipalities have expired without renewal.

All but 27 of the existing franchises cover a 30-year period from the date enacted. The exceptions are 23 franchises, each with a term of 10 years and expiring between 2005 and 2013; two franchises each with a term of 15 years and expiring in 2017; one 30-year franchise that was extended in 1999 for 5 years expiring in 2005; and one franchise with a term of 20 years expiring in 2020. Of the 108 franchises, 46 expire between January 1, 2005, and December 31, 2015, and 62 expire between January 1, 2016, and December 31, 2034.

Ongoing negotiations and, in some cases, litigation are taking place with certain municipalities to reach agreement on franchise terms and to enact new franchise ordinances. See PART II, ITEM 7, "Other Matters," for a discussion of PEF's franchise litigation.

Wholesale Competition

See PART I, ITEM 1, "General," under Competition for a discussion of wholesale competition.

Stranded Costs

The largest stranded cost exposure for PEF is its commitment to QFs. PEF has taken a proactive approach to this industry issue. PEF continues to seek ways to address the impact of escalating payments from contracts it was obligated to sign under provisions of PURPA. See PART I, ITEM 1, "General," under Competition for further discussion.

REGULATORY MATTERS

General

PEF is subject to the jurisdiction of the FPSC with respect to, among other things, rates and service for electric energy sold at retail, retail service territory and issuances of securities. In addition, PEF is subject to regulation by the FERC with respect to transmission and sales of wholesale power, accounting and certain other matters. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus a reasonable rate of return on its equity. Increased competition as a result of industry restructuring may affect the ratemaking process.

Retail Rate Matters

The FPSC authorizes retail "base rates" that are designed to provide a utility with the opportunity to earn a specific rate of return on its "rate base," or average investment in utility plant. These rates are intended to cover all reasonable and prudent expenses of utility operations and to provide investors with a fair rate of return.

In March 2002, the parties in PEF's rate case entered into a Stipulation and Settlement Agreement (the Agreement) related to retail rate matters. The Agreement was approved by the FPSC and is generally effective from May 1, 2002, through December 31, 2005. The Agreement eliminates the authorized Return on Equity (ROE) range normally used by the FPSC for the purpose of addressing earning levels, provided, however, that if PEF's base rate earnings fall below a 10% return on equity, PEF may petition the FPSC to amend its base rates. The Agreement is described in more detail in Note 8C.

In January 2005, in anticipation of the expiration of the Agreement, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2006. In its notice, PEF requested the FPSC to approve calendar year 2006 as the projected test period for setting new base rates. The request for increased base rates is based on the fact that PEF has faced significant cost increases over the past decade and expects its operational costs to continue to increase. These costs include the costs associated with completion of the Hines 3 generation facility, extraordinary hurricane damage costs including capital costs which are not expected to be directly recoverable, the need to replenish the depleted storm reserve and the expected infrastructure investment necessary to meet high customer expectations, coupled with the demands placed on PEF as a result of strong customer growth. Related risks are described in more detail in the "Risk Factors" section.

Fuel and Other Cost Recovery

PEF's operating costs not covered by the utility's base rates include fuel, purchased power, energy conservation expenses and specific environmental costs. The state commission allows electric utilities to recover certain of these costs through various cost recovery clauses, to the extent the commission determines in an annual hearing that such costs are prudent. In addition, in December 2002, the FPSC approved an Environmental Cost Recovery Clause (ECRC), which permits the Company to recover the costs of specified environmental projects to the extent these expenses are found to be prudent in an annual hearing and not otherwise included in base rates. Costs are recovered through this recovery clause in the same manner as the other existing clause mechanisms.

The FPSC's annual determination results in the addition of a rider to a utility's base rates to reflect the approval of these costs and to reflect any past over- or under-recovery. Due to the regulatory treatment of these costs and the method allowed for recovery, changes from year to year have no material impact on operating results.

In accordance with a regulatory order, PEF accrues $6 million annually to a storm damage reserve and is allowed to defer losses in excess of the accumulated reserve for major storms. Under the order, the storm reserve is charged with operation and maintenance expenses related to storm restoration and with capital expenditures related to storm restoration that are in excess of expenditures assuming normal operating conditions.

As of December 31, 2004, $291 million of hurricane restoration costs in excess of the previously recorded storm reserve of $47 million had been classified as a regulatory asset recognizing the probable recoverability of these costs. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail ratepayers over a two-year period. Hearings on PEF's petition for recovery of $252 million of storm costs filed with the FPSC are scheduled to begin on March 30, 2005 (See Note 3).

PEF's January 2005 notice to the FPSC of its intent to file for an increase in its base rates effective January 1, 2006, anticipates the need to replenish the depleted storm reserve balance and adjust the annual $6 million accrual in light of recent storm history to restore the reserve to an adequate level over a reasonable time period.

NUCLEAR MATTERS

In late 2002, CR3 received a license amendment authorizing a small power level increase. The power level increase of approximately four MW was implemented in February 2003.

See PART I, ITEM 1, "Nuclear Matters," for further discussion of these and other nuclear matters.

ENVIRONMENTAL MATTERS

There are two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation costs. In addition, there are distribution substations and transformers that are also anticipated to incur investigation and remediation costs. At this time, PEF cannot determine the total costs that may be incurred in connection with the remediation of all sites. See Note 22 for further discussion of these environmental matters.

FUELS

The Fuels business segment owns an array of assets that produce, transport and deliver fuel and provide related services for the open market. The Fuels business segment has subsidiaries that produce oil and gas products, blend and transload coal, mine coal and produce a solid coal-based synthetic fuel. This product has been classified as a synthetic fuel within the meaning of Section 29 of the Internal Revenue Service Code (Section 29). Sales of synthetic fuel therefore qualify for tax credits, as more fully described below.

The current combined assets of Fuels that are involved in fuel extraction, manufacturing and delivery include:

- Natural gas properties in Texas and Louisiana producing approximately 22 Bcf equivalent per year;
- Five terminals on the Ohio River and its tributaries, part of the trucking, rail and barge network for coal delivery;
- Two active coal-mining complexes, expected to produce approximately 3 to 5 million tons per year:
- Four wholly owned synthetic fuel entities, a majority owned synthetic fuel entity and a minority interest in one synthetic fuel entity, capable of producing up to 16 million tons per year;
- Majority-ownership in a barge partnership that transports coal products from the mouth of the Mississippi River to PEF's Crystal River facility in Florida.

During 2003, Progress Fuels acquired 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 approximately $168 million (See Note 5B).

In December 2004, the Company sold certain gas-producing properties and related assets owned by Winchester Production, a wholly owned subsidiary of Progress Fuels Corporation (See Note 4A).

SYNTHETIC FUELS TAX CREDITS

The Company has substantial operations associated with the production of coal-based synthetic fuels. The production and sale of these products qualifies for federal income tax credits so long as certain requirements are satisfied. These operations are subject to numerous risks.

Although the Company believes that it operates its synthetic fuel facilities in compliance with applicable legal requirements for claiming the credits, its four Earthco facilities are under audit by the IRS. IRS field auditors have taken an adverse position with respect to the Company's compliance with one of these legal requirements, and if the Company fails to prevail with respect to this position it could incur significant liability and/or lose the ability to claim the benefit of tax credits carried forward or generated in the future. Similarly, the Financial Accounting Standards Board may issue new accounting rules that would require that uncertain tax benefits (such as those associated with the Earthco plants) be probable of being sustained in order to be recorded on the financial statements; if adopted, this provision could have an adverse financial impact on the Company.

The Company's ability to utilize tax credits is dependent on having sufficient tax liability. Any conditions that negatively impact the Company's tax liability, such as weather, could also diminish the Company's ability to utilize credits, including those previously generated, and the synthetic fuel is generally not economical to produce absent the credits. Finally, the tax credits associated with synthetic fuels may be phased out if market prices for crude oil exceed certain prices.

The Company's synthetic fuel operations and related risks are described in more detail in Note 23E and in the "Risk Factors" section.

COMPETITION

Fuels' synthetic fuel operations and coal operations compete in the eastern United States steam and industrial coal markets. Factors contributing to the success in these markets include a competitive cost structure and strategic locations. There are, however, numerous competitors in each of these markets, although no one competitor is dominant in any industry.

Fuels' gas production operations compete in the East Texas and North Louisiana region. Factors contributing to success include a competitive cost structure. Although there are numerous small, independent competitors in this market, the major oil and gas producers dominate this industry.

ENVIRONMENTAL MATTERS

See Note 22 for a discussion of Fuels' environmental matters.

COMPETITIVE COMMERCIAL OPERATIONS (CCO)

The CCO business segment is responsible for marketing energy in the wholesale market outside the realm of retail regulation. CCO currently owns six electricity generation facilities with approximately 3,100 MW of generation capacity, and it has contractual rights to an additional 2,500 MW of generation capacity from mixed fuel generation facilities through its agreements with 16 Georgia electric membership cooperatives (EMCs). CCO has contracts for its combined production capacity of approximately 77% for 2005, approximately 81% for 2006 and approximately 75% for 2007.

The energy CCO markets is sold under both term contracts and in the spot market. CCO purchases fuel, such as oil and natural gas for use in the generation of electricity. The Company believes that there are adequate sources of fuel for CCO's expected fuel requirements. CCO also uses financial instruments to manage the risks associated with fluctuating commodity prices to hedge the economic value of its portfolio of assets.

In May 2003, PVI acquired from Williams Energy Marketing and Trading, a subsidiary of the Williams Companies, Inc., a long-term full-requirements power supply agreement at fixed prices with Jackson, for $188 million. In 2004, PVI executed wholesale power-supply agreements with 15 Georgia electric membership cooperatives (EMCs) to serve their electricity needs through 2010.

COMPETITION

CCO does not operate in the same environment as regulated utilities. It operates specifically in the wholesale market, which means competition is its primary driver. CCO competes in the eastern United States utility markets. Factors contributing to the success in these markets include a competitive cost structure and strategic locations.

RAIL SERVICES

The Rail Services business segment is one of the largest integrated and diversified suppliers of railroad and transit system products and services in North America and is headquartered in Albertville, Alabama. Rail Services' principal business functions include two business units: Locomotive and Railcar Services (LRS) and Engineering and Track-work Services (ETS).

The LRS unit is primarily focused on railroad rolling stock that includes freight cars, transit cars and locomotives, the repair and maintenance of these units, the manufacturing or reconditioning of major components for these units and scrap metal recycling. The ETS unit focuses on rail and other track components, the infrastructure that supports the operation of rolling stock, and the equipment used in maintaining the railroad infrastructure and right-of-way. The Recycling division of the LRS unit supports both business units through its reclamation of reconditionable material and is a major supplier of recyclable scrap metal to North American steel mills and foundries through its processing locations as well as its scrap brokerage operations.

Rail Services' key railroad industry customers are Class 1 railroads, regional and short line railroads, North American transit systems, railcar and locomotive builders, and railcar lessors. The U.S. operations are located in 23 states and include further geographic coverage through mobile crews on a selected basis. This coverage allows for Rail Services' customer base to be dispersed throughout the U.S., Canada and Mexico.

In February 2005, Progress Energy signed a definitive agreement to sell its Progress Rail subsidiary to subsidiaries of One Equity Partners LLC for a sales price of $405 million. Proceeds from the sale are expected to be used to reduce debt. See Note 24 for more information.

In March 2003, the Company signed a letter of intent to sell the majority of Railcar Ltd., assets to The Andersons, Inc. A definitive purchase agreement was signed in November 2003 and the transaction closed in February 2004 (See Note 4C).

ENVIRONMENTAL MATTERS

See Note 22 for a discussion of Rail's environmental matters.

CORPORATE AND OTHER BUSINESS SEGMENT

GENERAL

The Corporate and Other Businesses segment includes the operations of PT LLC and Strategic Resource Solutions Corp. (SRS) and holding company operations. This segment also includes other nonregulated operations of PEC and FPC.

PROGRESS TELECOM LLC

In December 2003, PTC and Caronet, both wholly owned subsidiaries of Progress Energy, and EPIK, a wholly owned subsidiary of Odyssey, contributed substantially all of their assets and transferred certain liabilities to PT LLC, a subsidiary of PTC. 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 holds a 55% ownership interest in, and is the parent of, PT LLC; Odyssey holds a combined 45% ownership interest in PT LLC through EPIK and Caronet. The accounts of PT LLC have been included in the Company's Consolidated Financial Statements since the transaction date.

PT LLC has data fiber network transport capabilities that stretch from New York to Miami, Florida, with gateways to Latin America, and conducts primarily a carrier's carrier business. PT LLC markets wholesale fiber-optic-based capacity service in the Eastern United States to long-distance carriers, Internet service providers and other telecommunications companies. PT LLC also markets wireless structure attachments to wireless communication companies and governmental entities. At December 31, 2004, PT LLC owned and managed more than 8,500 route miles and more than 420,000 fiber miles of fiber-optic cable.

PT LLC competes with other providers of fiber-optic telecommunications services, including local exchange carriers and competitive access providers, in the Eastern United States.

Lease revenue for dedicated transport and data services is generally billed in advance on a fixed rate basis and recognized over the period the services are provided. Revenues relating to design and construction of wireless infrastructure are recognized upon completion of services for each completed phase of design and construction.

For additional information regarding asset and investment impairments related to the Company's investments in the telecommunications industry, see Notes 7 and 10 to the PEC Consolidated Financial Statements.

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PROGRESS ENERGY

	Years Ended December 31				
	2004	2003	2002	2001	2000(d)
Energy supply (millions of kilowatt-hours)					
Generated – Steam	50,782	51,501	49,734	48,732	31,132
Nuclear	30,445	30,576	30,126	27,301	23,857
Combustion Turbines/Combined Cycle	9,695	7,819	8,522	6,644	1,337
Hydro	802	955	491	245	441
Purchased	13,466	13,848	14,305	14,469	5,724
Total energy supply (Company share)	105,190	104,699	103,178	97,391	62,491
Jointly owned share (a)	5,395	5,213	5,258	4,886	4,505
Total system energy supply	110,585	109,912	108,436	102,277	66,996
Average fuel cost (per million Btu)					
Fossil	$ 3.17	$ 2.94	$ 2.62	$ 2.46	$ 1.96
Nuclear fuel	$ 0.44	$ 0.44	$ 0.44	$ 0.45	$ 0.45
All fuels	$ 2.21	$ 2.05	$ 1.84	$ 1.77	$ 1.30
Energy sales (millions of kilowatt-hours)					
Retail					
Residential	35,350	34,712	33,993	31,976	15,365
Commercial	24,753	24,110	23,888	23,033	12,221
Industrial	17,105	16,749	16,924	17,204	14,762
Other Retail	4,475	4,382	4,287	4,149	1,626
Wholesale	18,323	19,841	19,204	17,715	15,012
Unbilled	449	189	275	(1,045)	1,098
Total energy sales	100,455	99,983	98,571	93,032	60,084
Company uses and losses	3,936	3,753	3,604	3,478	2,286
Total energy requirements	104,391	103,736	102,175	96,510	62,370
Electric revenues (in millions)					
Retail	$ 6,066	$ 5,620	$ 5,515	$ 5,462	$ 2,799
Wholesale	843	915	881	923	665
Miscellaneous revenue	244	206	205	172	81
Total electric revenues	$ 7,153	$ 6,741	$ 6,601	$ 6,557	$ 3,545
Peak demand of firm load (thousands of kW)					
System (b)	19,711	19,876	20,365	19,166	18,874
Company	19,126	19,235	19,746	18,564	18,272
Total regulated capability at year-end (thousands of kW)					
Fossil plants	16,522	16,522	16,006	15,826 (e)	14,747
Nuclear plants	4,286 (h)	4,220 (g)	4,127 (f)	4,008	4,008
Hydro plants	218	218	218	218	218
Purchased	2,852	2,826	2,929	2,890	2,278
Total system capability	23,878	23,786	23,280	22,942	21,251
Less jointly owned portion (c)	714	698	682	668	662
Total Company capability – regulated	23,164	23,088	22,598	22,274	20,589

(a) Amounts represent co-owner's share of the energy supplied from the six generating facilities that are jointly owned.
(b) Amounts represent the combined summer noncoincident system net peaks for PEC and PEF.
(c) For PEC, this represents Power Agency's retained share of jointly owned facilities per the Power Coordination Agreement between PEC and Power Agency.
(d) Amounts include information for PEF since November 30, 2000, the date of acquisition.
(e) Amount includes 459 MW related to Rowan units that were transferred to PVI in February 2002.
(f) Amount includes power uprates for Harris, Brunswick 1 and Robinson. The Maximum Dependable Capability (MDC) for Harris was restated January 2002; the MDCs for Brunswick 1 and Robinson were restated January 2003.
(g) Amount includes power uprates for CR3 and Brunswick 2. The MDCs were restated January 2004.
(h) Amount includes power uprate for Brunswick 1; the MDC was restated January 2005.

REGULATED OPERATING STATISTICS – PROGRESS ENERGY CAROLINAS

	Years Ended December 31				
	2004	2003	2002	2001	2000
Energy supply (millions of kilowatt-hours)					
Generated – Steam	**28,632**	28,522	28,547	27,913	29,520
Nuclear	**23,742**	24,537	23,425	21,321	23,275
Combustion Turbines/Combined Cycle	**1,926**	1,344	1,934	802	733
Hydro	**802**	955	491	245	441
Purchased	**4,023**	4,467	5,213	5,296	4,878
Total energy supply (Company share)	**59,125**	59,825	59,610	55,577	58,847
Power Agency share (a)	**4,794**	4,670	4,659	4,348	4,505
Total system energy supply	**63,919**	64,495	64,269	59,925	63,352
Average fuel cost (per million Btu)					
Fossil	**$ 2.52**	$ 2.29	$ 2.16	$ 1.91	$ 1.83
Nuclear fuel	**$ 0.42**	$ 0.43	$ 0.43	$ 0.44	$ 0.45
All fuels	**$ 1.57**	$ 1.43	$ 1.38	$ 1.26	$ 1.21
Energy sales (millions of kilowatt-hours)					
Retail					
Residential	**16,003**	15,283	15,239	14,372	14,091
Commercial	**13,019**	12,557	12,468	11,972	11,432
Industrial	**13,036**	12,749	13,089	13,332	14,446
Other Retail	**1,432**	1,408	1,437	1,423	1,423
Wholesale	**13,221**	15,518	15,024	12,996	14,582
Unbilled	**91**	(44)	270	(534)	679
Total energy sales	**56,802**	57,471	57,527	53,561	56,653
Company uses and losses	**2,323**	2,354	2,083	2,016	2,194
Total energy requirements	**59,125**	59,825	59,610	55,577	58,847
Electric revenues (in millions)					
Retail	**$ 2,953**	$ 2,824	$ 2,796	$ 2,666	$ 2,609
Wholesale	**575**	687	651	634	577
Miscellaneous revenue	**100**	78	92	44	122
Total electric revenues	**$ 3,628**	$ 3,589	$ 3,539	$ 3,344	$ 3,308
Peak demand of firm load (thousands of kW) (g)					
System	**11,192**	11,771	11,977	11,376	11,157
Company	**10,607**	11,130	11,358	10,774	10,555
Total regulated capability at year-end (thousands of kW)					
Fossil plants	**8,816**	8,816	8,816	8,648 (c)	7,569
Nuclear plants	**3,448** (f)	3,382 (e)	3,293 (d)	3,174	3,174
Hydro plants	**218**	218	218	218	218
Purchased	**1,545**	1,513	1,617	1,586	978
Total system capability	**14,027**	13,929	13,944	13,626	11,939
Less Power Agency-owned portion (b)	**645**	629	613	599	593
Total Company capability	**13,382**	13,300	13,331	13,027	11,346

(a) Amounts represent Power Agency's share of the energy supplied from the four generating facilities that are jointly owned.

(b) Amounts represent Power Agency's retained share of jointly owned facilities per the Power Coordination Agreement between PEC and Power Agency.

(c) Amount includes 459 MW related to Rowan units that were transferred to PVI in February 2002.

(d) Amount includes power upgrades for Harris, Brunswick 1 and Robinson. The MDC for Harris was restated January 2002; the MDCs for Brunswick 1 and Robinson were restated January 2003.

(e) Amount includes power uprate for Brunswick 2; the MDC was restated January 2004.

(f) Amount includes power uprate for Brunswick 1; the MDC was restated January 2005.

(g) Amount is the summer peak demand.

ITEM 2. PROPERTIES

The Company believes that its physical properties and those of its subsidiaries are adequate to carry on its and their businesses as currently conducted. The Company and its subsidiaries maintain property insurance against loss or damage by fire or other perils to the extent that such property is usually insured.

ELECTRIC – PEC

At December 31, 2004, PEC's 18 generating plants represent a flexible mix of fossil, nuclear, hydroelectric, combustion turbines and combined cycle resources, with a total summer generating capacity of 12,482 MW. Of this total, Power Agency owns approximately 694 MW. On December 31, 2004, PEC had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEC Ownership (in %)		Summer Net Capability (a) (in MW)	
STEAM TURBINES								
Asheville	Skyland, N.C.	2	1964-1971	Coal	100		392	
Cape Fear	Moncure, N.C.	2	1956-1958	Coal	100		316	
Lee	Goldsboro, N.C.	3	1952-1962	Coal	100		407	
Mayo	Roxboro, N.C.	1	1983	Coal	83.83		745	(b)
Robinson	Hartsville, S.C.	1	1960	Coal	100		174	
Roxboro	Roxboro, N.C.	4	1966-1980	Coal	96.32	(c)	2,462	(b)
Sutton	Wilmington, N.C.	3	1954-1972	Coal	100		613	
Weatherspoon	Lumberton, N.C.	3	1949-1952	Coal	100		176	
	Total	19					5,285	
COMBINED CYCLE								
Cape Fear	Moncure, N.C.	2	1969	Oil	100		84	
Richmond	Hamlet, N.C.	1	2002	Gas/Oil	100		472	
	Total	3					556	
COMBUSTION TURBINES								
Asheville	Skyland, N.C.	2	1999-2000	Gas/Oil	100		330	
Blewett	Lilesville, N.C.	4	1971	Oil	100		52	
Darlington	Hartsville, S.C.	13	1974-1997	Gas/Oil	100		812	
Lee	Goldsboro, N.C.	4	1968-1971	Oil	100		91	
Morehead City	Morehead City, N.C.	1	1968	Oil	100		15	
Richmond	Hamlet, N.C.	5	2001-2002	Gas/Oil	100		775	
Robinson	Hartsville, S.C.	1	1968	Gas/Oil	100		15	
Roxboro	Roxboro, N.C.	1	1968	Oil	100		15	
Sutton	Wilmington, N.C.	3	1968-1969	Gas/Oil	100		64	
Wayne County	Goldsboro, N.C.	4	2000	Gas/Oil	100		668	
Weatherspoon	Lumberton, N.C.	4	1970-1971	Gas/Oil	100		138	
	Total	42					2,975	
NUCLEAR								
Brunswick	Southport, N.C.	2	1975-1977	Uranium	81.67		1,838	(b)(d)
Harris	New Hill, N.C.	1	1987	Uranium	83.83		900	(b)
Robinson	Hartsville, S.C.	1	1971	Uranium	100		710	
	Total	4					3,448	
HYDRO								
Blewett	Lilesville, N.C.	6	1912	Water	100		22	
Marshall	Marshall, N.C.	2	1910	Water	100		5	
Tillery	Mount Gilead, N.C.	4	1928-1960	Water	100		86	
Walters	Waterville, N.C.	3	1930	Water	100		105	
	Total	15					218	
TOTAL		83					12,482	

(a) Amounts represent PEC's net summer peak rating, gross of co-ownership interest in plant capacity.
(b) Facilities are jointly owned by PEC and Power Agency. The capacities shown include Power Agency's share.
(c) PEC and Power Agency are co-owners of Unit 4 at the Roxboro Plant. PEC's ownership interest in this 700 MW turbine is 87.06%.
(d) During 2004, a power uprate increased the net summer capability of Unit 1 to 938 MW. The MDC was restated in January 2005.

At December 31, 2004, including both the total generating capacity of 12,482 MW and the total firm contracts for purchased power of approximately 1,545 MW, PEC had total capacity resources of approximately 14,027 MW.

The Power Agency has undivided ownership interests of 18.33% in Brunswick Unit Nos. 1 and 2, 12.94% in Roxboro Unit No. 4 and 16.17% in the Harris Plant and Mayo Unit No. 1. Otherwise, PEC has good and marketable title to its principal plants and important units, subject to the lien of its mortgage and deed of trust, with minor exceptions, restrictions, and reservations in conveyances, as well as minor defects of the nature ordinarily found in properties of similar character and magnitude. PEC also owns certain easements over private property on which transmission and distribution lines are located.

At December 31, 2004, PEC had approximately 6,000 circuit miles of transmission lines including 300 miles of 500 kilovolt (kV) lines and 3,000 miles of 230 kV lines. PEC also had approximately 45,000 circuit miles of overhead distribution conductor and 18,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 12,000,000 kilovolt-ampere (kVA) in 2,405 transformers. Distribution line transformers numbered approximately 509,700 with an aggregate capacity of approximately 21,000,000 kVA.

ELECTRIC – PEF

At December 31, 2004, PEF's 14 generating plants represent a flexible mix of fossil, nuclear, combustion turbine and combined cycle resources with a total summer generating capacity (including jointly owned capacity) of 8,544 MW. At December 31, 2004, PEF had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEF Ownership (in %)	Summer Net Capability (a) (in MW)	
STEAM TURBINES							
Anclote	Holiday, Fla.	2	1974-1978	Gas/Oil	100	993	
Bartow	St. Petersburg, Fla.	3	1958-1963	Gas/Oil	100	444	
Crystal River	Crystal River, Fla.	4	1966-1984	Coal	100	2,302	
Suwannee River	Live Oak, Fla.	3	1953-1956	Gas/Oil	100	143	
	Total	12				3,882	
COMBINED CYCLE							
Hines	Bartow, Fla.	2	1999-2003	Gas/Oil	100	998	
Tiger Bay	Fort Meade, Fla.	1	1997	Gas	100	207	
	Total	3				1,205	
COMBUSTION TURBINES							
Avon Park	Avon Park, Fla.	2	1968	Gas/Oil	100	52	
Bartow	St. Petersburg, Fla.	4	1958-1972	Gas/Oil	100	187	
Bayboro	St. Petersburg, Fla.	4	1973	Oil	100	184	
DeBary	DeBary, Fla.	10	1975-1992	Gas/Oil	100	667	
Higgins	Oldsmar, Fla.	4	1969-1970	Gas/Oil	100	122	
Intercession City	Intercession City, Fla.	14	1974-2000	Gas/Oil	100 (c)	1,041	(b)
Rio Pinar	Rio Pinar, Fla.	1	1970	Oil	100	13	
Suwannee River	Live Oak, Fla.	3	1980	Gas/Oil	100	164	
Turner	Enterprise, Fla.	4	1970-1974	Oil	100	154	
University of Florida Cogeneration	Gainesville, Fla.	1	1994	Gas	100	35	
	Total	47				2,619	
NUCLEAR							
Crystal River	Crystal River, Fla.	1	1977	Uranium	91.78	838	(b)
	Total	1				838	
TOTAL		63				8,544	

(a) Amounts represent PEF's net summer peak rating, gross of co-ownership interest in plant capacity.
(b) Facilities are jointly owned. The capacities shown include joint owners' share.
(c) PEF and Georgia Power Company (Georgia Power) are co-owners of a 143 MW advanced combustion turbine located at PEF's Intercession City site (P11). Georgia Power has the exclusive right to the output of this unit during the months of June through September. PEF has that right for the remainder of the year.

At December 31, 2004, PEF had total capacity resources of approximately 10,042 MW, including both the total generating capacity of 8,544 MW and the total firm contracts for purchased power of 1,498 MW.

Several entities have acquired undivided ownership interests in CR3 in the aggregate amount of 8.22%. The joint ownership participants are: City of Alachua – 0.08%, City of Bushnell – 0.04%, City of Gainesville – 1.41%, Kissimmee Utility Authority – 0.68%, City of Leesburg – 0.82%, Utilities Commission of the City of New Smyrna Beach – 0.56%, City of Ocala – 1.33%, Orlando Utilities Commission – 1.60% and Seminole Electric Cooperative, Inc. – 1.70%. PEF and Georgia Power are co-owners of a 143 MW advance combustion turbine located at PEF's Intercession City site (P11). Georgia Power has the exclusive right to the output of this unit during the months of June through September. PEF has that right for the remainder of the year. Otherwise, PEF has good and marketable title to its principal plants and important units, subject to the lien of its mortgage and deed of trust, with minor exceptions, restrictions and reservations in conveyances, as well as minor defects of the nature ordinarily found in properties of similar character and magnitude. PEF also owns certain easements over private property on which transmission and distribution lines are located.

At December 31, 2004, PEF had approximately 5,000 circuit miles of transmission lines including 200 miles of 500 kV lines and about 1,500 miles of 230 kV lines. PEF also had approximately, 22,000 circuit miles of overhead distribution conductor and 13,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 45,000,000 kVA in 616 transformers. Distribution line transformers numbered approximately 365,000 with an aggregate capacity of approximately 18,000,000 kVA.

FUELS

Progress Fuels controls, either directly or through subsidiaries, coal reserves located in eastern Kentucky and southwestern Virginia of approximately 46 million tons and controls, through mineral leases, additional estimated coal reserves of approximately 48 million tons. The reserves controlled include substantial quantities of high quality, low sulfur coal that is appropriate for use at PEF's existing generating units. Progress Fuels' total production of coal during 2004 was approximately 3.4 million tons.

In connection with its coal operations, Progress Fuels' business units own and operate surface and underground mines, coal processing and loadout facilities in southeastern Kentucky and southwestern Virginia. Other subsidiaries own and operate a river terminal facility in eastern Kentucky, a railcar-to-barge loading facility in West Virginia, two bulk commodity terminals on the Kanawha River near Charleston, West Virginia, and a bulk commodity terminal on the Ohio River near Huntington, West Virginia. Progress Fuels and its subsidiaries employ both Company and contract miners in their mining activities.

The Fuels business segment, through its business units, has an interest in six synthetic fuel entities. Four of the entities are wholly owned, one is majority owned and one is minority owned. These facilities are in six different locations in West Virginia, Virginia and Kentucky.

Fuels' oil and gas production in 2004 was 30.4 Bcf equivalent. Fuels has oil and gas leases in East Texas and Louisiana with total proven oil and gas reserves of approximately 247 Bcf equivalent.

CCO

At December 31, 2004, CCO had the following nonregulated generation plants in service.

Project	Location	Construction Start Date	Commercial Operation Date	Configuration/ Number of Units	MW (a)
Monroe Units 1 and 2	Monroe, Ga.	4Q 1998/1Q 2000	4Q 1999/2Q 2001	Simple-Cycle, 2	315
Rowan Phase I (b)	Salisbury, N.C.	1Q 2000	2Q 2001	Simple-Cycle, 3	459
Walton (c)	Monroe, Ga.	2Q 2000	2Q 2001	Simple-Cycle, 3	460
DeSoto Units	Arcadia, Fla.	2Q 2001	2Q 2002	Simple-Cycle, 2	320
Effingham	Rincon, Ga.	1Q 2001	3Q 2003	Combined-Cycle, 1	480
Rowan Phase II (b)	Salisbury, N.C.	4Q 2001	2Q 2003	Combined-Cycle, 1	466
Washington (c)	Sandersville, Ga.	2Q 2002	2Q 2003	Simple-Cycle, 4	600
TOTAL					3,100

(a) Amounts represent CCO's summer rating.
(b) This project was transferred from PEC to PVI in February 2002.
(c) These projects were purchased from LG&E Energy Corp. in February 2002.

RAIL SERVICES

Progress Rail is one of the largest integrated processors of railroad materials in the United States, and is a leading supplier of new and reconditioned freight car parts; rail, rail welding and track work components; railcar repair facilities; railcar and locomotive leasing; maintenance-of-way equipment and scrap metal recycling. It has facilities in 23 states, Mexico and Canada.

Progress Rail owns and/or operates approximately 2,000 railcars and 50 locomotives that are used for the transportation and shipping of coal, steel and other bulk products.

In February 2005, Progress Energy signed a definitive agreement to sell its Progress Rail subsidiary to subsidiaries of One Equity Partners LLC for a sales price of $405 million. Proceeds from the sale are expected to be used to reduce debt. See Note 24 for more information.

PT LLC

PT LLC provides wholesale telecommunications services throughout the Southeastern United States. PT LLC incorporates more than 420,000 fiber miles of fiber-optic cable in its network, including more than 189 Points-of-Presence, or physical locations where a presence for network access exists.

ITEM 3. LEGAL PROCEEDINGS

Legal proceedings are included in the discussion of the Company's business in PART I, ITEM 1 under "Environmental Matters," and are incorporated by reference herein.

1. **U.S. Global, LLC v. Progress Energy, Inc. et al., Case No. 03004028-03 and Progress Synfuel Holdings, Inc. et al., v. U.S. Global, LLC, Case No. 03004028-03**

A number of Progress Energy, Inc. 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 (1) an interest in two synthetic fuel facilities currently owned by the Progress Affiliates, and (2) 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, Florida, 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, North Carolina, seeking declaratory relief consistent with the Company's 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 Company cannot predict the outcome of these matters, but will vigorously defend against the allegations.

2. **In re Progress Energy, Inc. Securities Litigation, Master File No. 04-CV-636 (JES)**

On February 3, 2004, Progress Energy, Inc. was served with a class action complaint alleging violations of federal security laws in connection with the Company's issuance of Contingent Value Obligations (CVOs). The action was filed by Gerber Asset Management LLC in the United States District Court for the Southern District of New York and names Progress Energy, Inc.'s former Chairman William Cavanaugh III and Progress Energy, Inc. as defendants. The Complaint alleges that Progress Energy failed to timely disclose the impact of the Alternative Minimum Tax required under Sections 55-59 of the Internal Revenue Code (Code) on the value of certain CVOs issued in connection with the Florida Progress Corporation merger. The suit seeks unspecified compensatory damages, as well as attorneys' fees and litigation costs.

On March 31, 2004, a second class action complaint was filed by Stanley Fried, Raymond X. Talamantes and Jacquelin Talamantes against William Cavanaugh III and Progress Energy, Inc. in the United States District Court for the Southern District of New York alleging violations of federal securities laws arising out of the Company's issuance of CVOs nearly identical to those alleged in the February 3, 2004, Gerber Asset Management complaint. On April 29, 2004, the Honorable John E. Sprizzo ordered among other things that (1) the two class action cases be consolidated, (2) Peak6 Capital Management LLC shall serve as the lead plaintiff in the consolidated action, and (3) the lead plaintiff shall file a consolidated amended complaint on or before June 15, 2004.

The lead plaintiff filed a consolidated amended complaint on June 15, 2004. In addition to the allegations asserted in the Gerber Asset Management and Fried complaints, the consolidated amended complaint alleges that the Company failed to disclose that excess fuel credits could not be carried over from one tax year into later years. On July 30, 2004, the Company filed a motion to dismiss the complaint; plaintiff submitted its opposition brief on September 14, 2004. The Court heard oral argument on the Company's motion to dismiss on November 15, 2004; it has not, to date, rendered a decision on this motion.

The Company cannot predict the outcome of this matter, but will vigorously defend against the allegations.

For a discussion of certain other legal matters, see Note 23E to the Progress Energy Consolidated Financial Statements.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

NONE

EXECUTIVE OFFICERS OF THE REGISTRANTS

Name	Age	Recent Business Experience
*Robert B. McGehee	61	**Chairman and Chief Executive Officer,** Progress Energy, May 2004 and March 2004, respectively, to present. Mr. McGehee joined the Company (formerly CP&L) in 1997 as Senior Vice President and General Counsel. Since that time, he has held several senior management positions of increasing responsibility. Most recently, Mr. McGehee served as President and Chief Operating Officer of the Company, having responsibility for the day-to-day operations of the Company's regulated and nonregulated businesses. Prior to that, Mr. McGehee served as President and Chief Executive Officer of Progress Energy Service Company, LLC. Before joining Progress Energy, Mr. McGehee chaired the board of Wise Carter Child & Caraway, a law firm headquartered in Jackson, Miss. He primarily handled corporation, contract, nuclear regulatory and employment matters. During the 1990s, he also provided significant counsel to U.S. companies on reorganizations, business growth initiatives and preparing for deregulation and other industry changes.
William S. Orser	60	**Group President, Energy Supply,** PEC and PEF, November 2000 to present. (separating from the Company, effective April 1, 2005.) Mr. Orser is responsible for the operation of 38 utility and nonregulated power plants of Progress Energy. He also oversees plant construction and the organizations that support those plants, including the Company's System Planning and Operations function. Mr. Orser joined Progress Energy (formerly CP&L) in 1993 as Executive Vice President and Chief Nuclear Officer. He later became Executive Vice President – Energy Supply, PEC, a position he held until the acquisition of FPC in 2000. Before joining the Company in April 1993, Mr. Orser was an executive at the Detroit Edison Company, serving as Executive Vice President – Nuclear Generation. Previously, he worked with Portland General Electric Co.
William D. Johnson	51	**President and Chief Operating Officer,** Progress Energy, January 2005 to present; Group President, PEC, January 2005 to present; Executive Vice President, PEC and PEF, November 2000 to present. Mr. Johnson has been with Progress Energy (formerly CP&L) since 1992 and most recently served as Group President, Energy Delivery, Progress Energy, January 2004 to December 2004. Prior to that, he was President, CEO and Corporate Secretary, Progress Energy Service Company, LLC, October 2002 to December 2003. He also served as Executive Vice President – Corporate Relations & Administrative Services, General Counsel and Secretary of Progress Energy. Mr. Johnson served as Vice President – Legal Department and Corporate Secretary, CP&L from 1997 to 1999. Before joining Progress Energy, Johnson was a partner with the Raleigh office of Hunton & Williams, where he specialized in the representation of utilities.

Peter M. Scott III	55	**President and Chief Executive Officer,** Progress Energy Service Company, LLC, January 2004 to present; Executive Vice President, PEC and PEF, 2000 to present. Mr. Scott has been with the Company since May 2000 and most recently served as Executive Vice President and Chief Financial Officer of Progress Energy, Inc., May 2000 to December 2003. In that position, Mr. Scott oversaw the Company's strategic planning, financial and enterprise risk management functions. Before joining Progress Energy, Mr. Scott was the president of Scott, Madden & Associates, Inc., a general management consulting firm headquartered in Raleigh, N.C. that he founded in 1983. The firm served clients in a number of industries, including energy and telecommunications. Particular practice area specialties for Mr. Scott included strategic planning and operations management.
Geoffrey S. Chatas	42	**Executive Vice President and Chief Financial Officer,** Progress Energy, Inc., Progress Energy Service Company, LLC, FPC, PEC and PEF, January 2004 to present. Mr. Chatas oversees the Company's accounting, strategic planning, tax, financial and regulatory services and enterprise risk management functions. He previously served as Senior Vice President, Progress Energy, October 2003 to December 2003. Mr. Chatas served in various positions with American Electric Power (AEP), a multi-state energy holding company based in Columbus, Ohio from 1997 until he joined Progress Energy. Mr. Chatas' last position at AEP was Senior Vice President – Finance and Treasurer for AEP. During his time at AEP, he managed investor relations and corporate finance. In addition, Mr. Chatas held executive financial positions at Banc One and Citibank.
Robert H. Bazemore, Jr.	50	**Chief Accounting Officer and Controller,** Progress Energy, Inc., June 2000 to present; Controller, FPC and PEF, November 2000 to present; Chief Accounting Officer, FPC, November 2000 to present; Vice President and Controller, Progress Energy Service Company, LLC, August 2000 to present; Chief Accounting Officer and Controller, PEC, May 2000 to present. Mr. Bazemore has been with Progress Energy (formerly CP&L) since 1986 and has served in a number of roles in corporate support and field positions, including Director, CP&L, Operations & Environmental Support Department, December 1998 to May 2000; Manager, CP&L Financial & Regulatory Accounting, September 1995 to December 1998. Prior to joining Progress Energy, Mr. Bazemore worked in managerial and accounting positions with companies in Roanoke, Va. and Jacksonville, Fla.
Donald K. Davis	59	**Executive Vice President,** PEC, May 2000 to present. Mr. Davis is also President and Chief Executive Officer, SRS, June 2000 to present and was President and Chief Executive Officer, NCNG, July 2000 to September 2003. Mr. Davis joined the Company in May 2000 as Executive Vice President, Gas and Energy Services. Before joining the Company, Mr. Davis was Chairman, President and Chief Executive Officer of Yankee Atomic Electric Company, and served as Chairman, President and Chief Executive Officer of Connecticut Atomic Power Company from 1997 to May 2000 where he was

		responsible for two electric wholesale generating companies. Before joining Yankee Atomic Power Co., Davis served as a principal of PRISM Consulting Inc., a utility management consulting firm he founded in 1992.
Fred N. Day IV	61	**President and Chief Executive Officer,** PEC, October 2003 to present; Executive Vice President, PEF, November 2000 to present. Mr. Day oversees all aspects of Carolinas Delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Executive Vice President, PEC and PEF. During his more than 30 years with Progress Energy (formerly CP&L), Mr. Day has held several management positions of increasing responsibility. He was promoted to Vice President – Western Region in 1995.
*H. William Habermeyer, Jr.	62	**President and Chief Executive Officer,** PEF, November 2000 to present. Mr. Habermeyer joined Progress Energy (formerly PEC) in 1993 after a career in the U.S. Navy. During his tenure with the Company, Mr. Habermeyer has served as Vice President – Nuclear Services and Environmental Support; Vice President – Nuclear Engineering; and Vice President – Western Region. While overseeing Western Region operations, Mr. Habermeyer was responsible for regional distribution management, customer support and community relations.
C. S. Hinnant	60	**Senior Vice President and Chief Nuclear Officer,** PEC, June 1998 to present. Mr. Hinnant is also Senior Vice President, PEF, November 2000 to present. Mr. Hinnant joined Progress Energy (formerly CP&L) in 1972 at the Brunswick Nuclear Plant near Southport, N.C., where he held several positions in the startup testing and operating organizations. He left Progress Energy in 1976 to work for Babcock and Wilcox in the Commercial Nuclear Power Division, returning to Progress Energy in 1977. Since that time, he has served in various management positions at three of Progress Energy's nuclear plant sites.
*Jeffrey J. Lyash	43	**Senior Vice President,** PEF, November 2003 to present. Mr. Lyash oversees all aspects of energy delivery operations for PEF. Prior to coming to PEF, Mr. Lyash was Vice President – Transmission in Energy Delivery in the Carolinas since January 2002. Mr. Lyash joined Progress Energy in 1993 and spent his first eight years with the Company at the Brunswick Nuclear Plant in Southport, N.C. His last position at Brunswick was as Director of site operations.
John R. McArthur	49	**Senior Vice President, General Counsel and Secretary** of Progress Energy, January 2004 to present. Mr. McArthur oversees the Audit Services, Corporate Communications, Legal, Regulatory and Corporate Relations – Florida, and State Public Affairs departments, and the Environmental and Health and Safety sections. Mr. McArthur is also Senior Vice President and Corporate Secretary, FPC and PEC, and Senior Vice President, PEF, January 1 to present. Previously, he served the Company as Senior Vice President – Corporate Relations (December 2002 to December 2003) and as Vice President – Public Affairs (December 2001 to December 2002). Before joining Progress Energy in December 2001, Mr. McArthur was a member of North Carolina Governor Mike Easley's senior management

		team, handling major policy initiatives as well as media and legal affairs. He also directed Governor Easley's transition team after the election of 2000. From November of 1997 until November of 2000, Mr. McArthur handled state government affairs in 10 southeastern states for General Electric Co. Prior to joining General Electric Co., Mr. McArthur served as chief counsel in the North Carolina Attorney General's office, where he supervised utility, consumer, health care, and environmental protection issues. Before that, he was a partner at Hunton & Williams.
E. Michael Williams	56	**Senior Vice President,** PEC and PEF, June 2000 and November 2000, respectively, to present. Before joining the Company in 2000, Mr. Williams was with Central and Southwest Corp., Inc. and subsidiaries for 28 years and served in various positions prior to becoming Vice President – Fossil Generation in Dallas.
Lloyd M. Yates	44	**Senior Vice President,** PEC, January 2005 to present. Mr. Yates is responsible for managing the four regional vice presidents in the PEC organization. He served PEC as Vice President – Transmission from November 2003 to December 2004. Mr. Yates served as Vice President – Fossil Generation for PEC from 1998 to 2003. Before joining the Company in 1998, Mr. Yates was with PECO Energy, where he had served in a number of engineering and management roles over 16 years. His last position with PECO was as general manager – Operations in the Company's power operations group.

*Indicates individual is an executive officer of Progress Energy, Inc., but not Carolina Power & Light Company.

PART II

ITEM 5. MARKET FOR THE REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Progress Energy

Progress Energy's Common Stock is listed on the New York Stock Exchange. The high and low intra-day stock sales prices for each quarter for the past two years, and the dividends declared per share are as follows:

2004	High	Low	Dividends Declared
First Quarter	**$ 47.95**	**$ 43.02**	**$0.575**
Second Quarter	**47.50**	**40.09**	**0.575**
Third Quarter	**44.32**	**40.76**	**0.575**
Fourth Quarter	**46.10**	**40.47**	**0.590**

2003	High	Low	Dividends Declared
First Quarter	$ 46.10	$ 37.45	$0.560
Second Quarter	48.00	38.99	0.560
Third Quarter	45.15	39.60	0.560
Fourth Quarter	46.00	41.60	0.575

The December 31 closing price of the Company's Common Stock was $45.24 for 2004 and $45.26 for 2003. As of March 4, 2005, the Company had 67,160 holders of record of Common Stock.

Neither Progress Energy's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends. Progress Energy's subsidiaries have provisions restricting dividends in certain limited circumstances (See Note 13B).

Issuer purchases of equity securities for fourth quarter of 2004 are as follows:

Period	(a) Total Number of Shares (or Units) Purchased(1)	(b) Average Price Paid Per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs(1)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs(1)
October 1 – October 31(2)	191,436	$ 41.90	N/A	N/A
November 1 – November 30	N/A	N/A	N/A	N/A
December 1 – December 31	N/A	N/A	N/A	N/A
Total:	191,436	$ 41.90	N/A	N/A

(1) As of December 31, 2004, Progress Energy does not have any publicly announced plans or programs to purchase shares of its common stock.

(2) All shares were purchased in open-market transactions by the plan administrator to satisfy share delivery requirements under the Progress Energy 401(k) Savings and Stock Ownership Plan (See Note 11A).

PEC

Since 2000, Progress Energy has owned all of PEC's common stock, and as a result there is no established public trading market for the stock. PEC has not issued or repurchased any equity securities since becoming a wholly owned subsidiary of Progress Energy. For the past three years, PEC has paid quarterly dividends to Progress Energy totaling the amounts shown in the Statements of Common Equity in the PEC Consolidated Financial Statements. PEC has provisions restricting dividends in certain limited circumstances (See Note 8 and 13 to the PEC Consolidated Financial Statements). PEC does not have any equity compensation plans under which its equity securities are issued.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

PROGRESS ENERGY, INC.

The selected consolidated financial data should be read in conjunction with the consolidated financial statements and the notes thereto included elsewhere in this report.

(in millions, except per share data)

Years Ended December 31	2004	2003	2002	2001	2000(a)
Operating results					
Operating revenues	$ 9,772	$ 8,741	$ 8,091	$ 8,129	$ 3,769
Income from continuing operations before cumulative effect	$ 753	$ 811	$ 552	$ 541	$ 478
Net Income	$ 759	$ 782	$ 528	$ 542	$ 478
Per share data					
Basic earnings					
Income from continuing operations	$ 3.11	$ 3.42	$ 2.54	$ 2.64	$ 3.04
Net income	$ 3.13	$ 3.30	$ 2.43	$ 2.65	$ 3.04
Diluted earnings					
Income from continuing operations	$ 3.10	$ 3.40	$ 2.53	$ 2.63	$ 3.03
Net income	$ 3.12	$ 3.28	$ 2.42	$ 2.64	$ 3.03
Assets (c)	$ 25,993	$ 26,093	$ 24,272	$ 23,701	$ 22,875
Capitalization					
Common stock equity	$ 7,633	$ 7,444	$ 6,677	$ 6,004	$ 5,424
Preferred stock of subsidiaries – not subject to mandatory redemption	93	93	93	93	93
Minority interest	36	30	18	12	–
Long-term debt, net (b)	9,521	9,934	9,747	8,619	4,904
Current portion of long-term debt	349	868	275	688	184
Short-term obligations	684	4	695	942	4,959
Total capitalization and total debt	$ 18,316	$ 18,373	$ 17,505	$ 16,358	$ 15,564
Dividends declared per common share	$ 2.32	$ 2.26	$ 2.20	$ 2.14	$ 2.08

(a) Operating results and balance sheet data include information for FPC since November 30, 2000, the date of acquisition.
(b) Includes long-term debt to affiliated trust of $270 million at December 31, 2004, and 2003 (See Note 19).
(c) All periods have been restated for the reclassification of certain cost of removal amounts.

PROGRESS ENERGY CAROLINAS, INC.

The selected consolidated financial data should be read in conjunction with the consolidated financial statements and the notes thereto included elsewhere in this report.

(in millions) Years Ended December 31	2004	2003	2002	2001	2000(a)
Operating results					
Operating revenues	$ 3,629	$ 3,600	$ 3,554	$ 3,360	$ 3,528
Net income	$ 461	$ 482	$ 431	$ 364	$ 461
Earnings for common stock	$ 458	$ 479	$ 428	$ 361	$ 458
Assets (c)	$ 10,787	$ 10,938	$ 10,442	$ 10,640	$ 10,552
Capitalization					
Common stock equity	$ 3,072	$ 3,237	$ 3,089	$ 3,095	$ 2,852
Preferred stock – not subject to mandatory redemption	59	59	59	59	59
Long-term debt, net	2,750	3,086	3,048	2,698	3,134
Current portion of long-term debt	300	300	–	600	–
Short-term obligations (b)	337	29	438	309	486
Total capitalization and total debt	$ 6,518	$ 6,711	$ 6,634	$ 6,761	$ 6,531

(a) Operating results and balance sheet data do not include information for NCNG, SRS, Monroe Power Company or PVI subsequent to July 1, 2000, the date PEC distributed its ownership interest in the stock of these companies to Progress Energy.

(b) Includes notes payable to affiliated companies, related to the money pool program, of $116 million, $25 million and $48 million at December 31, 2004, 2003 and 2001, respectively.

(c) All periods have been restated for the reclassification of certain cost of removal amounts.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management's Discussion and Analysis contains forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review the "Risk Factors" sections and "SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS" for a discussion of the factors that may impact any such forward-looking statements made herein.

Management's Discussion and Analysis should be read in conjunction with the Progress Energy Consolidated Financial Statements.

INTRODUCTION

The Company's reportable business segments and their primary operations include:

- Progress Energy Carolinas Electric (PEC Electric) – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina;
- Progress Energy Florida (PEF) – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida;
- Competitive Commercial Operations (CCO) – engaged in nonregulated electric generation operations and marketing activities primarily in the southeastern United States;
- Fuels – primarily engaged in natural gas production in Texas and Louisiana, coal mining and related services, and the production of synthetic fuels and related services, which are located in Kentucky, West Virginia and Virginia; and
- Rail Services (Rail) – engaged in various rail and railcar-related services in 23 states, Mexico and Canada.

The Progress Ventures business unit consists of the Fuels and CCO operating segments. The Corporate and Other category includes other businesses engaged in other nonregulated business areas, including telecommunications, primarily in the eastern United States, and energy services operations and holding company results, which do not meet the requirements for separate segment reporting disclosure.

In 2004, the Company realigned its business segments to no longer report the other nonregulated businesses as a reportable business segment. For comparative purposes, 2003 and 2002 segment information has been restated to align with the 2004 reporting structure.

Strategy

Progress Energy is an integrated energy company, with its primary focus on the end-use and wholesale electricity markets. The Company operates in retail utility markets in the southeastern United States and competitive markets in the eastern United States. The target is to develop a business mix of approximately 80% regulated and 20% nonregulated business. The Company is focused on achieving the following key goals: restoring balance sheet strength and flexibility, disciplined capital and operations and maintenance (O&M) management to support earnings and current dividend policy and achieving constructive regulatory frameworks in all three regulated jurisdictions. A summary of the significant financial objectives or issues impacting Progress Energy, its regulated utilities and nonregulated operations is addressed more fully in the following discussion.

PROGRESS ENERGY, INC.

Progress Energy has several key financial objectives, the first of which is to achieve sustainable earnings growth in its three core energy businesses, which include PEC Electric, PEF and Progress Ventures (excluding synthetic fuels). In addition, the Company seeks to continue its track record of dividend growth, as the Company has increased its dividend for 17 consecutive years, and 29 of the last 30. The Company also seeks to restore balance sheet strength and flexibility by reducing its debt to total capitalization ratio through selected asset sales, free cash flow (defined as cash from operations less capital expenditures and common dividends) and increased equity from retained earnings and ongoing equity issuances.

In the short-term, the Company's ability to achieve its objectives will be impacted by, among other things, its ability to recover storm costs incurred during 2004, cash flow available to reduce debt after funding capital expenditures and common dividends, obtaining a reasonable rate agreement in Florida at the expiration of the current agreement in December 2005 and the outcome of the ongoing Internal Revenue Service (IRS) audit of the Company's synthetic fuel facilities. The Company's long-term challenges include escalating nonfuel operating costs, the need for sufficient earnings growth to sustain the track record of dividend growth, and the scheduled expiration of the Section 29 tax credit program for its synthetic fuels business at the end of 2007.

The Company's ability to meet its financial objectives is largely dependent on the earnings and cash flows of its two regulated utilities. The regulated utilities contributed $797 million of net income and produced 100% of consolidated cash flow from operations in 2004. In addition, Fuels contributed $180 million of net income, of which $91 million represented synthetic fuel net income. Partially offsetting the net income contribution provided by the regulated utilities and Fuels was a loss of $236 million recorded at Corporate and Other, primarily related to interest expense on holding company debt.

While the Company's synthetic fuel operations currently provide significant earnings that are scheduled to expire at the end of 2007, the associated cash flow benefits from synthetic fuels are expected to come in the future when deferred tax credits are ultimately utilized. Credits that have been generated but not yet utilized are carried forward indefinitely as alternative minimum tax credits and will provide positive cash flow when utilized. At December 31, 2004, deferred credits were $745 million. See Note 23E and the "Risk Factors" section for additional information on the Company's synthetic fuel operations and its ability to utilize its current and future tax credits.

Progress Energy reduced its debt to total capitalization ratio to 57.6% at the end of 2004 as compared to 58.8% at the end of 2003. The Company seeks to continue to improve this ratio as it plans to reduce total debt with proceeds from asset sales, free cash flow (defined as cash from operations less capital expenditures and common dividends) and growth in equity from retained earnings and ongoing equity issuances. The Company expects total capital expenditures to be approximately $1.3 billion in both 2005 and 2006.

Progress Energy's ratings outlook was changed to "negative" from "stable" in 2004 by both Moody's and Standard & Poor's (S&P). Both ratings agencies cited the uncertainty around the timing of storm cost recovery, potential delays in the Company's de-leveraging plan, uncertainty about the upcoming rate case in Florida and uncertainty about the IRS audit of the Company's synthetic fuel partnerships in their ratings actions. The change in outlook has not materially affected Progress Energy's access to liquidity or the cost of its short-term borrowings. If Standard & Poor's lowers Progress Energy's senior unsecured rating one ratings category to BB+ from its current rating, it would be a noninvestment grade rating. The effect of a noninvestment grade rating would primarily be to increase borrowing costs. The Company's liquidity would essentially remain unchanged as the Company believes it could borrow under its revolving credit facilities instead of issuing commercial paper for its short-term borrowing needs. However, there would be additional funding requirements of approximately $450 million due to ratings triggers embedded in various contracts. See "Guarantees" Section under FUTURE LIQUIDITY AND CAPITAL RESOURCES below and "Risk Factors" for more information regarding the potential impact on the Company's financial condition and results of operations resulting from a ratings downgrade.

REGULATED UTILITIES

The regulated utilities earnings and operating cash flows are heavily influenced by weather, including related storm damage, the economy, demand for electricity related to customer growth, actions of regulatory agencies and cost controls.

Both PEC Electric and PEF operate in retail service territories that are forecasted to have income and population growth higher than the U.S. average. In recent years, lower industrial sales mainly related to weakness in the textile sector at PEC Electric have negatively impacted earnings growth. The Company does not expect any significant improvement in industrial sales in the near term. These combined factors under normal weather conditions are expected to contribute approximately 2% annual retail kilowatt-hour (KWh) sales growth at PEC Electric and approximately 3% annual retail kilowatt-hour (KWh) sales growth at PEF through at least 2007. The utilities must continue to invest significant capital in new generation, transmission and distribution facilities to support this load growth. Subject to regulatory approval, these investments are expected to increase the utilities' rate base, upon which additional return can be realized that creates the basis for long-term financial growth in the utilities. The Company will meet this load growth through the two previously planned approximately 500 MW combined-cycle units at PEF's Hines Energy Complex in 2005 and 2007. The contribution from the utilities' regulated wholesale business is expected to increase slightly in 2005 and be relatively flat over the following few years.

While the two utilities expect retail sales growth in the future, they are facing rising costs. The Company began a cost-management initiative in late 2004 to permanently reduce by $75-$100 million the projected growth in the Company's annual nonfuel O&M costs by the end of 2007. See "Cost Management Initiative" under RESULTS OF OPERATIONS for more information. The utilities expect capital expenditures to be approximately $1.1 billion in both 2005 and 2006. The Company will continue an approximate $900 million program of installing new emission-control equipment at PEC's coal-fired power plants in North Carolina. Operating cash flows are expected to be sufficient to fund capital spending in 2005 and in 2006.

The costs associated with the unprecedented series of major hurricanes that impacted the Company's service territories significantly impacted the utility operations in 2004. Restoration of the Company's systems from hurricane-related damage cost almost $400 million. Although PEF has filed for recovery of approximately $252 million of these storm costs, the timing of recovery is not certain at this time. See OTHER MATTERS below for more information on storm costs incurred during 2004.

PEC Electric and PEF continue to monitor progress toward a more competitive environment. No retail electric restructuring legislation has been introduced in the jurisdictions in which PEC Electric and PEF operate. As part of the Clean Smokestacks bill in North Carolina and an agreement with the Public Service Commission of South Carolina (SCPSC), PEC Electric is operating under a rate freeze in North Carolina through 2007 and an agreement not to seek a base retail electric rate increase in South Carolina through 2005. PEF is operating under a retail rate agreement in Florida through 2005. PEF has initiated a rate proceeding in 2005 regarding its future base rates. See Note 8 for further discussion of the utilities' retail rates.

NONREGULATED BUSINESSES

The Company's primary nonregulated businesses are CCO, Fuels and Progress Rail.

Cash flows and earnings of the nonregulated businesses are impacted largely by the ability to obtain additional term contracts or sell energy on the spot market at favorable terms, the volume of synthetic fuel produced and tax credits utilized, and volumes and prices of both coal and natural gas sales.

Progress Energy expects an excess of supply in the wholesale electric energy market for the next several years. During 2004, CCO entered into additional wholesale power contracts with cooperatives in Georgia and will serve approximately one-third of the Georgia cooperative market starting in 2005. CCO completed the build out of its nonregulated generation assets in 2003 and currently has total capacity of 3,100 MW. The Company has no current plans to expand its portfolio of nonregulated generating plants. CCO short-term challenges include absorbing the fixed costs associated with these plants and the general weakness in wholesale power markets. Three above-market tolling agreements for approximately 1,200 MW of capacity expired at the end of 2004. CCO has replaced the expired agreements with the increased cooperative load in Georgia. The increased cooperative load in Georgia will significantly increase CCO's revenue and cost of sales from 2004 to 2005 with lower margins expected. Currently CCO has contracts for its planned production capacity, which includes callable resources from the cooperatives, of approximately 77% for 2005, 81% for 2006 and 75% for 2007. CCO will continue its optimization strategy for the nonregulated generation portfolio.

Fuels will continue to develop its natural gas production asset base both as a long-term economic hedge for the Company's nonregulated generation fuel needs and to continue its presence in natural gas markets that will allow it to provide attractive returns for the Company's shareholders.

The Company has begun exploring strategic alternatives regarding the Fuels' coal mining business, which could include divesting assets. As of December 31, 2004, the carrying value of long-lived assets of the coal mining business was $66 million.

The Company, through its subsidiaries, is a majority owner in five entities and a minority owner in one entity that owns facilities that produce synthetic fuel as defined under the Internal Revenue Code. The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 if certain requirements are satisfied. These facilities have private letter rulings (PLRs) from the IRS with respect to their synthetic fuel operations. However, these PLRs do not address placed-in-service date requirements. The Company has resolved certain synthetic fuel tax credit issues with the IRS and is continuing to work with the IRS to resolve any remaining issues.

The Company cannot predict the final resolution of any outstanding matters. The Company has no current plans to alter its synthetic fuel production schedule as a result of these matters. The Company plans to produce approximately 8 to 12 million tons of synthetic fuel in 2005. Through December 31, 2004, the Company had generated approximately $1.5 billion of synthetic fuel tax credits to date (including FPC prior to the acquisition by the Company). See additional discussion of synthetic fuel tax credits in Note 23E and in the "Risk Factors" section.

In February 2005, Progress Energy signed a definitive agreement to sell its Progress Rail subsidiary to subsidiaries of One Equity Partners LLC for a sales price of $405 million. Proceeds from the sale are expected to be used to reduce debt. See Note 24 for more information.

Progress Energy and its consolidated subsidiaries are subject to various risks. For a complete discussion of these risks, see the Risk Factors section.

RESULTS OF OPERATIONS

FOR 2004 AS COMPARED TO 2003 AND 2003 AS COMPARED TO 2002

In this section, earnings and the factors affecting earnings are discussed. The discussion begins with a summarized overview of the Company's consolidated earnings, which is followed by a more detailed discussion and analysis by business segment.

Overview

For the year ended December 31, 2004, Progress Energy's net income was $759 million or $3.13 per share compared to $782 million or $3.30 per share for the same period in 2003. The decrease in net income as compared to prior year was due primarily to:

- Reduction in synthetic fuel earnings due to lower synthetic fuel sales due to the impact of hurricanes during the year.
- Lower off-system wholesale sales, primarily at PEC Electric.
- Higher O&M expenses at PEC Electric.
- Recording of litigation settlement reached in the civil suit by Strategic Resource Solutions (SRS).
- Decreased nonregulated generation earnings due to receipt of a contract termination payment on a tolling agreement in 2003, loss recognized on early extinguishment of debt in 2004 and higher fixed costs and interest charges in 2004.
- Reduction in revenues due to customer outages in Florida associated with the hurricanes.
- Increased interest charges due to the reversal of interest expense for resolved tax matters in 2003.

Partially offsetting these items were:

- Favorable weather in the Carolinas.
- Reduction in revenue sharing provisions in Florida.
- Favorable customer growth in both the Carolinas and Florida.
- Increased margins as a result of the allowed return on the Hines 2 Plant in Florida.
- Increased earnings for natural gas operations, which include the gain recorded on the disposition of certain Winchester Production Company assets.
- Increased earnings for Rail operations.
- Unrealized gains recorded on contingent value obligations (CVOs).
- Reduction in impairments recorded for an investment portfolio and long-lived assets.
- Reduction in losses recorded for discontinued operations.
- Reduction in losses recorded for changes in accounting principles.

For the year ended December 31, 2003, Progress Energy's net income was $782 million, or $3.30 per share, compared to $528 million, or $2.43 per share, for the same period in 2002. Income from continuing operations before the cumulative effect of changes in accounting principles and discontinued operations was $811 million in 2003, a 47% increase from $552 million in 2002. Net income for 2003 increased compared to 2002 primarily due to the inclusion in 2002 of an impairment of $265 million after-tax related to assets in the telecommunications and rail businesses. The Company recorded impairments of $23 million after-tax in 2003 on an investment portfolio and on long-lived assets. The increase in net income in 2003 of $12 million, excluding the impairments, is primarily due to:

- Increase in retail customer growth at the utilities.
- Growth in natural gas production and sales.
- Higher synthetic fuel sales.
- Absence of severe storm costs incurred in 2002 in the Carolinas.
- Lower loss recorded in 2003 related to the sale of North Carolina Natural Gas Company (NCNG), with the majority of the loss on the sale being recorded in 2002.
- Lower interest charges in 2003.

Partially offsetting these items were the:
- Net impact of the 2002 Florida Rate settlement.
- Impact of the change in the fair value of the CVOs.
- Milder weather in 2003 as compared to 2002.
- Increased benefit-related costs.
- Higher depreciation expense at both utilities and the Fuels and CCO segments.
- The impact of changes in accounting principles in 2003.

Basic earnings per share decreased in 2004 and increased in 2003 due in part to the factors outlined above. Dilution related to issuances under the Company's Investor Plus and employee benefit programs in 2004 also reduced basic earnings per share by $0.06 in 2004. Dilution related to a November 2002 equity issuance of 14.7 million shares and issuances under the Company's Investor Plus and employee benefit programs in 2002 and 2003 also reduced basic earnings per share by $0.33 in 2003.

Beginning in the fourth quarter of 2003, the Company ceased recording portions of the Fuels segment's operations, primarily synthetic fuel facilities, one month in arrears. As a result, earnings for the year ended December 31, 2003, included 13 months of operations, resulting in a net income increase of $2 million for the year.

The Company's segments contributed the following profit or loss from continuing operations:

(in millions)	2004	Change	2003	Change	2002
PEC Electric	$ 464	$ (51)	$ 515	$ 2	$ 513
PEF	333	38	295	(28)	323
Fuels	180	(55)	235	59	176
CCO	(4)	(24)	20	(7)	27
Rail services	16	17	(1)	41	(42)
Total segment profit (loss)	989	(75)	1,064	67	997
Corporate and other	(236)	17	(253)	192	(445)
Total income from continuing operations	753	(58)	811	259	552
Discontinued operations, net of tax	6	14	(8)	16	(24)
Cumulative effect of changes in accounting principles	–	21	(21)	(21)	–
Net income	$ 759	$ (23)	$ 782	$ 254	$ 528

In March 2003, the SEC completed an audit of Progress Energy Service Company, LLC (Service Company), and recommended that the Company change its cost allocation methodology for allocating Service Company costs. As part of the audit process, the Company was required to change the cost allocation methodology for 2003 and record retroactive reallocations between its affiliates in the first quarter of 2003 for allocations originally made in 2001 and 2002. This change in allocation methodology and the related retroactive adjustments have no impact on consolidated expense or earnings. The new allocation methodology, as compared to the previous allocation methodology, generally decreases expenses in the regulated utilities and increases expenses in the nonregulated businesses. The regulated utilities' reallocations are within O&M expense, while the diversified businesses' reallocations are generally within diversified business expenses. The impact on the individual lines of business is included in the following discussions.

Cost Management Initiative

On February 28, 2005, as part of a previously announced cost management initiative, the executive officers of the Company approved a workforce restructuring. The restructuring will result in a reduction of approximately 450 positions and is expected to be completed in September of 2005. The cost management initiative is designed to permanently reduce by $75-100 million the projected growth in the Company's annual operation and maintenance expenses by the end of 2007. In addition to the workforce restructuring, the cost management initiative includes a voluntary enhanced retirement program.

In connection with the cost management initiative, the Company expects to incur one-time pre-tax charges of approximately $130 million. Approximately $30 million of that amount relates to payments for severance benefits, and will be recognized in the first quarter of 2005 and paid over time. The remaining approximately $100 million will be recognized in the second quarter of 2005 and relates primarily to postretirement benefits that will be paid over time to those eligible employees who elect to participate in the voluntary enhanced retirement program. Approximately 3,500 of the Company's 15,700 employees are eligible to participate in the voluntary enhanced retirement program. The total cost management initiative charges could change significantly depending upon how many eligible employees elect early retirement under the voluntary enhanced retirement program and the salary, service years and age of such employees (See Note 24).

Energy Delivery Capitalization Practice

The Company has reviewed its capitalization policies for its Energy Delivery business units in PEC and PEF. 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. The Company has implemented such changes effective January 1, 2005, which include more detailed classification of outage and emergency work and result in more precise estimation and a process of retesting 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 Company estimates that the combined impact for both utilities in 2005 will be that approximately $55 million of costs that would have been capitalized under the previous policies will be expensed. Pursuant to SFAS No. 71, PEC and PEF have informed the state regulators having jurisdiction over them of this change and that the new estimation process will be implemented effective January 1, 2005. The Company has also requested a method change from the IRS.

Progress Energy Carolinas Electric

PEC Electric contributed segment profits of $464 million, $515 million and $513 million in 2004, 2003 and 2002, respectively. The decrease in profits for 2004 as compared to 2003 is primarily due to higher O&M charges and lower wholesale revenues partially offset by the favorable impact of weather, increased revenues from customer growth and a reduction in investment losses and impairment charges compared to the prior year. The slight increase in profits in 2003, when compared to 2002, was primarily due to customer growth, strong wholesale sales during the first quarter of 2003, lower Service Company allocations and lower interest costs, which were offset by unfavorable weather in 2003, higher depreciation expense and increased benefit-related costs.

REVENUES

PEC Electric's electric revenues and the percentage change by year and by customer class are as follows:

(in millions) Customer Class	2004	% Change	2003	% Change	2002
Residential	$ 1,324	5.2	$ 1,259	1.5	$ 1,241
Commercial	888	4.5	850	2.2	832
Industrial	659	3.6	636	(1.4)	645
Governmental	82	3.8	79	1.3	78
Total retail revenues	2,953	4.6	2,824	1.0	2,796
Wholesale	575	(16.3)	687	5.5	651
Unbilled	10	–	(6)	–	15
Miscellaneous	90	7.1	84	9.1	77
Total electric revenues	$ 3,628	1.1	$ 3,589	1.4	$ 3,539

PEC Electric's electric energy sales and the percentage change by year and by customer class are as follows:

(in thousands of MWh) Customer Class	2004	% Change	2003	% Change	2002
Residential	**16,003**	4.7	15,283	0.3	15,239
Commercial	**13,019**	3.7	12,557	0.7	12,468
Industrial	**13,036**	2.3	12,749	(2.6)	13,089
Governmental	**1,431**	1.6	1,408	(2.0)	1,437
Total retail energy sales	**43,489**	3.6	41,997	(0.6)	42,233
Wholesale	**13,222**	(14.8)	15,518	3.3	15,024
Unbilled	**91**	–	(44)	–	270
Total MWh sales	**56,802**	1.2	57,471	(0.1)	57,527

PEC Electric's revenues, excluding recoverable fuel revenues of $933 million and $901 million for 2004 and 2003, respectively, increased $7 million. The increase in revenues was due primarily to increased retail revenues of $35 million as a result of favorable weather, with cooling degree days 16% above prior year. Retail customer growth contributed an additional $55 million in revenues in 2004. PEC Electric's retail customer base increased as approximately 26,000 new customers were added in 2004. The increase in retail revenues was offset partially by lower wholesale revenues. Wholesale revenues decreased $86 million when compared to $393 million in 2003. The decrease in PEC Electric's wholesale revenues in 2004 from 2003 is primarily the result of reduced excess generation sales. Revenues for 2003 included strong sales to the northeastern United States as a result of favorable market conditions. In addition, lower contracted capacity compared to 2003 further reduced wholesale revenues. The remaining reduction in wholesale revenues is attributable to an inelastic power market. While the cost of fuel continues to rise, the power market prices have not responded as quickly to the fuel increases. The differential between fuel cost and market price limited opportunities to enter the market. PEC monitors its wholesale contract portfolio on a regular basis. During 2003 and 2004, several contracts expired or were renegotiated at lower prices. Due to the slightly depressed wholesale market and increased competition, this trend could continue as contracts are renewed in the upcoming years. The expiration and renegotiation of wholesale contracts is a normal business activity. PEC actively manages its portfolio by seeking to sign new contracts to replace expiring arrangements.

PEC Electric's revenues, excluding recoverable fuel revenues of $901 million and $851 million in 2003 and 2002, respectively, were unchanged from 2002 to 2003. Milder weather in 2003, when compared to 2002, accounted for a $61 million retail revenue reduction. While heating degree days in 2003 were 4.8% above prior year, cooling degree days were 25.2% below prior year. However, the more severe weather in the northeast region of the United States during the first quarter of 2003 drove a $19 million increase in wholesale revenues. Additionally, retail customer growth in 2003 generated an additional $42 million of revenues in 2003. PEC Electric's retail customer base increased as approximately 23,000 new customers were added in 2003.

Downturns in the economy during 2002 and 2003 impacted energy usage within the industrial customer class. Total industrial revenues, excluding fuel revenues, declined during 2003 when compared to 2002 by $13 million, as sales to industrial customers decreased due to a general industrial slowdown. Decreases in the textile industry and the chemical industry were among the largest. This declining trend leveled out in 2004 as industrial sales increased in the primary and fabricated metal, chemicals, lumber and food industries. Industrial sales growth is expected to be flat or very low as expired textile quotas are expected to lower textile sales and balance gains in other industries.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation, as well as energy purchased in the market to meet customer load. Fuel and purchased power expenses are recovered primarily through cost recovery clauses, and, as such, changes in these expenses do not have a material impact on earnings. The difference between fuel and purchased power costs incurred and associated fuel revenues that are subject to recovery is deferred for future collection or refund to customers.

Fuel and purchased power expenses were $1.137 billion for 2004, which represents a $16 million increase compared to the same period in the prior year. Fuel used in electric generation increased $11 million to $836 million compared to the prior year. This increase is due to an increase in fuel used in generation of $78 million due to higher fuel costs and a change in generation mix. Higher fuel costs are being driven primarily by an increase in coal prices. Outages at several nuclear facilities during the year resulted in increased combustion turbine generation, which has a higher average fuel cost. See Part I, Item I, "Fuel and Purchased Power" of Electric – PEC for a summary of average fuel costs. The increase in fuel used in generation is offset by a reduction in deferred fuel expense as a result of the under-recovery of current period fuel costs. Purchased power expenses increased $5 million to $301 million compared to prior year. The increase in purchased power is due primarily to an increase in price.

Fuel and purchased power expenses were $1.121 billion for 2003, which represents a $22 million increase compared to the same period in the prior year. Fuel used in electric generation increased $73 million in 2003, compared to prior year, primarily due to higher prices incurred for coal, oil and natural gas used during generation. Costs for fuel per Btu increased for all three commodities during the year. See Part I, Item I, "Fuel and Purchased Power" of Electric – PEC for a summary of average fuel costs. Purchased power expense decreased $51 million in 2003, compared to $347 million in 2002, mainly due to a decrease in the volume purchased as milder weather reduced system requirements and due to the renegotiation at more favorable terms of two contracts that expired during the year.

Operations and Maintenance (O&M)

O&M expenses were $871 million for 2004, which represents an $89 million increase compared to 2003. This increase is driven primarily by higher outage costs and storm costs in 2004 than in the prior year. Outages increased O&M costs by $29 million primarily due to an increase in the number and scope of nuclear plant outages in 2004. In addition, costs associated with restoration efforts after severe storms increased O&M expense $18 million. Storm costs for 2004 included costs related to an ice storm and Hurricanes Charley and Ivan in the North Carolina service territory. PEC Electric also incurred storm costs in 2003; however, the Company requested and the NCUC approved deferral of these costs. The Company did not seek to defer costs associated with the ice storm, which hit the North Carolina service territory, and Hurricanes Charley and Ivan. O&M expenses also increased $9 million due to higher salary- and benefit-related expenditures. In addition, O&M charges in the prior year were favorably impacted by $16 million related to the retroactive reallocation of Service Company costs.

O&M expenses were $782 million in 2003, which represents a $20 million decrease compared to 2002. O&M expense in 2002 included severe storm costs of $27 million. Those costs, along with lower 2003 Service Company allocations of $16 million, due to the change in allocation methodology as required by the SEC in early 2003, are the primary reasons for decreased O&M expenses. This decrease was partially offset by higher benefit-related costs of $21 million. PEC Electric incurred O&M costs of $25 million related to three severe storms in 2003. The NCUC allowed deferral of $24 million of these storm costs. These costs are being amortized over a five-year period, beginning in the months the expenses were incurred. PEC Electric amortized $3 million of these costs in 2003, which is included in depreciation and amortization expense on the Consolidated Income Statement.

Depreciation and Amortization

Depreciation and amortization expense was $570 million for 2004, which represents an $8 million increase compared to 2003. This increase is attributable primarily to the impact of the NC Clean Air legislation. PEC Electric recorded the maximum amortization allowed under the legislation in 2004. NC Clean Air amortization increased $100 million to $174 million in 2004 compared to $74 million in 2003. Depreciation expense also increased $9 million for assets placed in service. These increases were partially offset by a reduction in depreciation expense related to depreciation studies filed during the year. During 2004, PEC met the requirements of both the NCUC and the SCPSC for the implementation of 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 compared to 2003. The reduction is due primarily to extended lives at each of PEC's nuclear units. The new rates became effective January 2004.

Depreciation and amortization increased $38 million in 2003, compared to $524 million in 2002. Depreciation and amortization increased $74 million related to the 2003 impact of the NC Clean Air legislation and decreased $53 million related to the 2002 impact of the accelerated nuclear amortization program. Both programs are approved by the state regulatory agencies and are discussed further at Notes 8B and 22. In addition, depreciation increased $19 million due to additional assets placed into service.

Taxes Other than on Income

Taxes other than on income were $173 million for 2004, which represents an $11 million increase compared to the prior year. This increase is due primarily to an increase in gross receipts taxes of $8 million related to an increase in revenues and a 2004 adjustment related to the prior year. The remaining variance in other taxes is due to an increase in property taxes of $7 million due to higher property appraisals partially offset by a reduction in payroll taxes of $4 million.

Taxes other than on income were $162 million in 2003, which represents a $4 million increase compared to prior year. This increase is due to an increase in property taxes and payroll taxes of $2 million each.

Interest Expense

Net interest expense was $192 million, $197 million and $212 million in 2004, 2003 and 2002, respectively. Declines in interest expense in 2003 resulted from reduced short-term debt and refinancing certain long-term debt with lower interest rate debt.

Income Tax Expense

Income tax expense was $237 million, $238 million and $237 million in 2004, 2003 and 2002, respectively. In 2004, 2003 and 2002, $22 million, $24 million and $35 million, respectively, of the tax benefit that was previously held at the Company's holding company was allocated to PEC Electric. As required by an SEC order issued in 2002, certain holding company tax benefits are allocated to profitable subsidiaries. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

Progress Energy Florida

PEF contributed segment profits of $333 million, $295 million and $323 million in 2004, 2003 and 2002, respectively. Profits for 2004 increased due to favorable customer growth, a reduction in the provision for revenue sharing, favorable wholesale revenues, the additional return on investment on the Hines 2 plant and reduced O&M expenses. These items were partially offset by unfavorable weather, a reduction in revenues related to the hurricanes, increased interest expense and increased depreciation expense from assets placed in service. The decrease in profits in 2003, when compared to 2002, was primarily due to the impact of the 2002 rate case stipulation, higher benefit-related costs primarily related to higher pension expense, higher depreciation and the unfavorable impact of weather. These amounts were partially offset by continued customer growth and lower interest charges.

In 2002, PEF's profits were affected by the outcome of the rate case stipulation, which included a one-time retroactive revenue refund, a decrease in retail rates of 9.25% (effective May 1, 2002), provisions for revenue sharing with the retail customer base, lower depreciation and amortization and increased service revenue rates (See Note 8C).

REVENUES

PEF's electric revenues and the percentage change by year and by customer class, as well as the impact of the rate case settlement on revenue, are as follows:

(in millions)					
Customer Class	2004	% Change	2003	% Change	2002
Residential	**$ 1,806**	6.8	$ 1,691	2.8	$ 1,645
Commercial	**853**	15.3	740	1.2	731
Industrial	**254**	16.0	219	3.8	211
Governmental	**211**	16.6	181	4.6	173
Revenue sharing refund	**(11)**	–	(35)	–	(5)
Retroactive retail rate refund	**–**	–	–	–	(35)
Total retail revenues	**3,113**	11.3	2,796	2.8	2,720
Wholesale	**268**	18.1	227	(1.3)	230
Unbilled	**7**	–	(2)	–	(3)
Miscellaneous	**137**	4.6	131	13.9	115
Total electric revenues	**$ 3,525**	11.8	$ 3,152	2.9	$ 3,062

PEF's electric energy sales and the percentage change by year and by customer class are as follows:

(in thousands of MWh)					
Customer Class	2004	% Change	2003	% Change	2002
Residential	19,347	(0.4)	19,429	3.6	18,754
Commercial	11,734	1.6	11,553	1.2	11,420
Industrial	4,069	1.7	4,000	4.3	3,835
Governmental	3,044	2.4	2,974	4.4	2,850
Total retail energy sales	38,194	0.6	37,956	3.0	36,859
Wholesale	5,101	18.0	4,323	3.4	4,180
Unbilled	358	–	233	–	5
Total MWh sales	43,653	2.6	42,512	3.6	41,044

PEF's revenues, excluding recoverable fuel and other pass-through revenues of $2.007 billion and $1.692 billion for 2004 and 2003, respectively, increased $58 million. This increase was due primarily to favorable customer growth, which increased revenues $34 million. PEF has 37,000 additional retail customers compared to prior year. Revenues were also favorably impacted by a reduction in the provision for revenue sharing of $24 million. Results for 2003 included an additional refund of $18 million related to the 2002 revenue sharing provision as ordered by the FPSC in July 2003. In addition, improved wholesale sales increased revenues by $11 million. Included in fuel revenues is the recovery of depreciation and capital costs associated with the Hines Unit 2, which was placed into service in December 2003 and contributed $36 million in additional revenues in 2004. The recovery of the Hines Unit 2 costs through the fuel clause is in accordance with the 2002 rate stipulation (See Note 8C). These increases were partially offset by the reduction in revenues related to customer outages for Hurricanes Charley, Frances and Jeanne of approximately $12 million and the impact of milder weather in the current year of $10 million.

PEF's revenues, excluding recoverable fuel and other pass-through revenues of $1.692 billion and $1.602 billion in 2003 and 2002, respectively, were unchanged from 2002 to 2003. Revenues were favorably impacted by $49 million in 2003, primarily as a result of customer growth (approximately 36,000 additional customers). In addition, other operating revenues were favorable by $16 million due primarily to higher wheeling and transmission revenues and higher service charge revenues (resulting from increased rates allowed under the 2002 rate settlement). These increases were offset by the negative impact of the rate settlement, which decreased revenues, lower wholesale sales and the impact of unfavorable weather. The provision for revenue sharing increased $12 million in 2003 compared to the $5 million provision recorded in 2002. Revenues in 2003 were also impacted by the final resolution of the 2002 revenue sharing provisions, as the FPSC issued an order in July 2003 that required PEF to refund an additional $18 million to customers related to 2002. The 9.25% rate reduction from the settlement accounted for an additional $46 million decline in revenues. The 2003 impact of the rate settlement was partially offset by the absence of the prior year interim rate refund of $35 million. Lower wholesale revenues (excluding fuel revenues) of $17 million and the $8 million impact of milder weather also reduced base revenues during 2003.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation, as well as energy purchased in the market to meet customer load. Fuel and purchased power expenses are recovered primarily through cost recovery clauses, and, as such, changes in these expenses do not have a material impact on earnings. The difference between fuel and purchased power costs incurred and associated fuel revenues that are subject to recovery is deferred for future collection or refund to customers.

Fuel and purchased power expenses were $1.742 billion in 2004, which represents a $306 million increase compared to 2003. This increase is due to increases in fuel used in electric generation and purchased power expenses of $305 million and $1 million, respectively. Higher system requirements and increased fuel costs in the current year account for $87 million of the increase in fuel used in electric generation. The remaining increase is due to the recovery of fuel expenses that were deferred in the prior year, partially offset by the deferral of current year under-recovered fuel expenses. In November 2003, the FPSC approved PEF's request for a cost adjustment in its annual fuel filing due to the rising costs of fuel. The new rates became effective January 2004.

Fuel used in generation and purchased power expenses were $1.436 billion in 2003, which represents an $87 million increase compared to the prior year. Higher costs to generate electricity and higher purchased power costs as a result of an increase in volume due to system requirements and higher natural gas prices resulted in a $229 million increase partially offset by the deferral of 2003 under-recovered fuel and purchased power expense of $142 million.

Operations and Maintenance (O&M)

O&M expenses were $630 million in 2004, which represents a $10 million decrease when compared to the prior year. This decrease is primarily related to favorable benefit-related costs of $16 million, primarily due to lower pension costs which resulted from improved pension asset performance.

O&M expenses were $640 million in 2003, which represents a $49 million increase when compared to the prior year. The increase is largely related to increases in certain benefit-related expenses of $36 million, which consisted primarily of higher pension expense of $27 million and higher operational costs related to the CR3 nuclear outage and plant maintenance.

Depreciation and Amortization

Depreciation and amortization expense was $281 million for 2004, which represents a decrease of $26 million when compared to the prior year, primarily due to the amortization of the Tiger Bay regulatory asset in the prior year. The Tiger Bay regulatory asset, for contract termination costs, was recovered pursuant to an agreement between PEF and the FPSC that was approved in 1997. The amortization of the regulatory asset was calculated using revenues collected under the fuel adjustment clause; as such, fluctuations in this expense did not have an impact on earnings. During 2003, Tiger Bay amortization was $47 million. The Tiger Bay asset was fully amortized in September 2003. The decrease in Tiger Bay amortization was partially offset by additional depreciation for assets placed in service, including depreciation for Hines Unit 2, of approximately $9 million. This depreciation expense is being recovered through the fuel cost recovery clause as allowed by the FPSC. See discussion of the return on Hines 2 in the revenues analysis above.

Depreciation and amortization was $307 million in 2003, which represents an increase of $12 million when compared to 2002. Depreciation increased primarily as a result of additional assets being placed into service that were partially offset by lower amortization of the Tiger Bay regulatory asset of $2 million, which was fully amortized in September 2003.

Taxes Other than on Income

Taxes other than on income were $254 million in 2004, which represents an increase of $13 million compared to the prior year. This increase is due to increases in gross receipts and franchise taxes of $8 million and $7 million, respectively, related to an increase in revenues and an increase in property taxes of $5 million due to increases in property placed in service and tax rates. These increases were partially offset by a reduction in payroll taxes of $7 million.

Taxes other than on income were $241 million in 2003, which represents an increase of $13 million compared to prior year. This increase was due to increases in payroll taxes of $10 million and increases in gross receipts and franchise taxes of $4 million combined.

Interest Expense

Interest charges, net were $114 million in 2004, which represents an increase of $23 million compared to the prior year. Interest charges, net were $91 million in 2003, which represents a $15 million decrease compared to the prior year. The fluctuations were primarily due to interest costs in 2003 being favorably impacted by the reversal of interest expense due to the resolution of certain tax matters.

Income Tax Expense

Income tax expense was $174 million, $147 million and $163 million in 2004, 2003 and 2002, respectively. In 2004, 2003 and 2002, $14 million, $13 million and $20 million, respectively, of the tax benefit that was previously held at the Company's holding company was allocated to PEF. As required by an SEC order issued in 2002, certain holding company tax benefits are allocated to profitable subsidiaries. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

Diversified Businesses

The Company's diversified businesses consist of the Fuels segment, the CCO segment and the Rail Services segment.

Fuels

The Fuels' segment operations include synthetic fuels production, natural gas production, coal extraction and terminal operations. Beginning in the fourth quarter of 2003, the Company ceased recording portions of Fuels' segment operations, primarily synthetic fuel facilities, one month in arrears. As a result, earnings for the year ended December 31, 2003, included 13 months of operations, resulting in a net income increase of $2 million for the year.

The following summarizes Fuels' segment profits:

(in millions)	2004	2003	2002
Synthetic fuel operations	$ 91	$ 205	$ 156
Natural gas operations	85	34	10
Coal fuel and other operations	4	(4)	10
Segment profits	$ 180	$ 235	$ 176

SYNTHETIC FUEL OPERATIONS

The production and sale of synthetic fuel generate operating losses, but qualify for tax credits under Section 29 of the Code, which more than offset the effect of such losses (See Note 23E).

The operations resulted in the following losses (prior to tax credits):

(in millions)	2004	2003	2002
Tons sold	8.3	12.4	11.2
After-tax losses (excluding tax credits)	$ (124)	$ (141)	$ (135)
Tax credits	215	346	291
Net profit	$ 91	$ 205	$ 156

The Company's synthetic fuel production levels and the amount of tax credits it can claim each year are a function of the Company's projected consolidated regular federal income tax liability. Synthetic fuel operations' net profits decreased in 2004 as compared to 2003 due primarily to a decrease in synthetic fuel production and an increase in operating expenses in 2004. The Company's total synthetic fuel production of approximately eight million tons in 2004 is down compared to 2003 production levels of approximately 12 million tons as a result of hurricane costs, which reduced the Company's projected 2004 regular tax liability and its corresponding ability to record tax credits from its synthetic fuel production. In addition, earnings in 2003 include a $13 million favorable tax credit true-up related to 2002.

As of September 30, 2004, the Company anticipated an ability to record approximately five million tons of synthetic fuels production based on the Company's projected regular tax liability for 2004. This estimate was based upon the Company's projected casualty loss as a result of the storms. Therefore, the Company recorded a charge of $79 million in the third quarter for tax credits associated with approximately 2.7 million tons sold during the year that the Company anticipated it would not be able to use. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from customers over a two-year period. Based on a reasonable expectation at December 31, 2004, that the FPSC will grant the requested recovery of the storm costs, the Company's loss from the casualty is less than originally anticipated. Accordingly, as of December 31, 2004, the Company's anticipated 2004 tax liability supported credits on approximately eight million tons. Therefore, the Company recorded tax credits of $90 million for the quarter ended December 31, 2004, for tax credits associated with approximately three million tons sold during the year that the Company now anticipates can be used. As of December 31, 2004, the Company anticipates that approximately $7 million of tax credits associated with approximately 0.2 million tons sold during the year could not be used (See Note 23E). The Company ceased operations at its Earthco facilities for the last three months of 2004 due to the decrease in the Company's projected 2004 tax liability, and these facilities were restarted in January 2005.

The Company believes its right to recover storm costs is well established; however, the Company cannot predict the timing or outcome of this matter. If the FPSC should deny PEF's petition for the recovery of storm costs in 2005, there could be a material impact on the amount of 2005 synthetic fuel production and results of operations.

Synthetic fuels' net profits for 2003 increased as compared to 2002 due to higher sales, improved margins and a higher tax credit per ton. The 2003 tax credits also include a $13 million favorable true-up from 2002. Additionally, synthetic fuels' results in 2003 include 13 months of operations for some facilities. Prior to the fourth quarter of 2003, results of these synthetic fuels' operations had been recognized one month in arrears. The net impact of this action increased net income by $2 million for the year.

NATURAL GAS OPERATIONS

Natural gas operations generated profits of $85 million, $34 million and $10 million for the years ended December 31, 2004, 2003 and 2002, respectively. Natural gas profits increased $51 million in 2004 compared to 2003. This increase is attributable primarily to the gain recognized on the sale of gas assets during the year. In December 2004, the Company sold certain gas-producing properties and related assets owned by Winchester Production Company, Ltd. (North Texas gas operations). 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 ($31 million net of taxes) was recognized in earnings rather than as a reduction of the basis of the Company's remaining oil and gas properties. In addition, an increase in production, coupled with higher gas prices in 2004, contributed to the increased earnings in 2004 as compared to 2003. Production levels increased resulting from the acquisition of North Texas Gas in late February 2003 and increased drilling in 2004. Volume and prices have increased 21% and 16%, respectively, for 2004 compared to 2003.

Natural gas profits increased to $34 million in 2003 compared to $10 million in 2002. The increase in production and price resulting from the acquisitions of Westchester in 2002 (renamed Winchester Energy in 2004) and North Texas Gas in the first quarter of 2003 drove increased revenue and earnings in 2003 compared to 2002. In October 2003, the Company completed the sale of certain gas-producing properties owned by Mesa Hydrocarbons, LLC (Mesa). See Notes 5B and 4D to the Progress Energy Consolidated Financial Statements for discussions of the North Texas Gas acquisitions and the Mesa disposition.

The following table summarizes the production and revenues of the natural gas operations by location:

	2004	2003	2002
Production in Bcf equivalent			
East Texas/LA gas operations	20	13	6
North Texas gas operations	10	7	–
Mesa	–	5	7
Total production	30	25	13
Revenues in millions			
East Texas/LA gas operations	$ 110	$ 65	$ 24
North Texas gas operations	52	38	–
Mesa	–	13	15
Total revenues	$ 162	$ 116	$ 39
Gross margin			
In millions of $	$ 126	$ 91	$ 29
As a % of revenues	78%	78%	74%

COAL FUEL AND OTHER OPERATIONS

Coal fuel and other operations generated profits of $4 million, losses of $4 million and profits of $10 million for the years ended December 31, 2004, 2003 and 2002, respectively. The increase in profits for 2004 is primarily due to higher volumes and margins for coal fuel operations of $16 million after-tax. In addition, coal results in 2003 included the recording of an impairment of certain assets at the Kentucky May coal mine totaling $11 million after-tax. This favorability was offset by a reduction in profits of $7 million after-tax for fuel transportation operations related to the waterborne transportation ruling by the FPSC (See Note 8C). Profits were also negatively impacted by higher corporate costs of $10 million in 2004. Corporate costs in the prior year included $4 million of favorability related to the reduction of an environmental reserve (See Note 22). The remaining unfavorability in corporate costs is attributable to increased interest expense related to unresolved tax matters and higher professional fees.

Coal fuel and other operations' profits decreased $9 million from 2002 to 2003. The decrease is due primarily to the recording of an impairment of certain assets at the Kentucky May coal mine totaling $11 million after-tax. The decrease in profits is also due to the impact of the retroactive Service Company allocation in 2003.

The Company is exploring strategic alternatives regarding the Fuels' coal mining business, which could include divesting these assets. As of December 31, 2004, the carrying value of long-lived assets of the coal mining business was $66 million. The Company cannot currently predict the outcome of this matter.

Competitive Commercial Operations

CCO generates and sells electricity to the wholesale market from nonregulated plants. These operations also include marketing activities. The following summarizes the annual revenues, gross margin and segment profits from the CCO plants:

(in millions)	2004	2003	2002
Total revenues	**$ 240**	$ 170	$ 92
Gross margin			
In millions of $	**$ 158**	$ 141	$ 83
As a % of revenues	**66%**	83%	90%
Segment profits (losses)	**$ (4)**	$ 20	$ 27

CCO's operations generated segment losses of $4 million in 2004 compared to segment profits of $20 million in 2003. Results for 2004 were favorably impacted by increased gross margin, which was more than offset by higher fixed costs and costs associated with the extinguishment of debt. Revenues increased for 2004 due to increased revenues from marketing and tolling contracts offset by a termination payment received on a marketing contract in 2003. Expenses for the cost of fuel and purchased power to supply marketing contracts partially offset the increased revenues netting to an increase in gross margin for 2004 as compared to 2003. Fixed costs increased $16 million pre-tax from additional depreciation and amortization on plants placed into service in 2003 and from an increase in interest expense of $13 million pre-tax due primarily to interest no longer being capitalized due to the completion of construction in the prior year. In addition, plant operating expenses increased $12 million pre-tax primarily due to higher gas transportation service charges, which increased over prior year due to a full period of expenses being reflected in current year results. CCO results for 2004 also include losses of $15 million pre-tax associated with the extinguishment of a debt obligation. CCO terminated the Genco financing arrangement in December 2004. The $15 million pre-tax loss is comprised of a $9 million write-off of remaining unamortized debt issuance costs and a $6 million realized loss on exiting the related interest rate hedge. Expenses were favorably impacted by a reduction in Service Company allocations. Results for 2003 were negatively impacted by the retroactive reallocation of Service Company costs of $3 million ($2 million after-tax).

CCO's operations generated segment profits of $20 million in 2003 compared to segment profits of $27 million in 2002. The increase in revenue for 2003 when compared to 2002 is primarily due to increased contracted capacity on newly constructed plants, energy revenue from a new, full-requirements power supply contract and a tolling agreement termination payment received during the first quarter. Generating capacity increased from 1,554 MW at December 31, 2002, to 3,100 MW at December 31, 2003, with the Effingham, Rowan Phase 2 and Washington plants being placed in service in 2003. In the second quarter of 2003, PVI acquired from Williams Energy Marketing and Trading a full-requirements power supply agreement with Jackson Electric Membership Corporation in Georgia for $188 million, which resulted in additional revenues of $21 million when compared to the same periods in 2002. The revenue increases related to higher volumes were partially offset by higher depreciation costs of $22 million, increased interest charges of $16 million and other fixed charges.

The Company has contracts for its planned production capacity, which includes callable resources from the cooperatives, of approximately 77% for 2005, approximately 81% for 2006 and approximately 75% for 2007. The Company continues to seek opportunities to optimize its nonregulated generation portfolio.

Rail Services

Rail Services' (Rail) operations represent the activities of Progress Rail and include railcar and locomotive repair, track-work, rail parts reconditioning and sales, scrap metal recycling, railcar leasing and other rail-related services.

Rail-contributed segment profits of $16 million for 2004 compared with segment losses of $1 million and $42 million for the years ended December 31, 2003, and 2002, respectively. Results in 2004 were favorably impacted by the strong scrap metal market in 2004. Revenues were $1.131 billion in 2004, which represents an increase of $284 million compared to prior year. This increase is due primarily to increased volumes and higher prices in recycling operations and in part to increased production and sales in locomotive and railcar services and engineering and track services. Tonnage for recycling operations is up approximately 35% on an annualized basis compared to 2003. The increase in tonnage, coupled with an increase in the average index price of approximately 80%, accounts for the significant increase in revenues year over year. The American Metal Market index price for #1 railroad heavy melt (which is used as the index for buying and selling of railcars) has increased to $191 as of December 31, 2004, from $106 as of December 31, 2003. Cost of goods sold was $990 million in 2004, which represents an increase of $252 million compared to the prior year. The increase in costs of goods sold is due to increased costs for inventory, labor and operations as a result of the increased volume in the recycling operations, locomotive and railcar services and engineering and track services. In addition, results in 2003 were negatively impacted by the retroactive reallocation of Service Company costs of $3 million after-tax. The favorability related to the reallocation was offset by an increase in general and administrative costs in 2004 related primarily to higher professional fees associated with divestiture efforts. See discussion below.

Rail's operations generated segment losses of $1 million in 2003 compared to segment losses of $42 million in 2002. The reduction in losses in 2003 compared to 2002 is due primarily to an impairment charge recorded in 2002. The net loss in 2002 includes a $40 million after-tax estimated impairment of assets held for sale related to Railcar Ltd., a leasing subsidiary of Progress Rail (See Note 4D). Excluding the impairment recorded in 2002, profits for Rail were flat year over year 2003 compared to 2002.

In February 2005, Progress Energy signed a definitive agreement to sell its Progress Rail subsidiary to subsidiaries of One Equity Partners LLC for a sales price of $405 million. Proceeds from the sale are expected to be used to reduce debt. See Note 24 for more information.

Corporate & Other

Corporate and Other consists of the operations of Progress Energy Holding Company (the holding company), Progress Energy Service Company and other consolidating and nonoperating entities. Corporate and Other also includes other nonregulated business areas including the operations of SRS and the telecommunication operations.

OTHER NONREGULATED BUSINESS AREAS

Progress Energy's other business areas include the operations of SRS and the telecommunications operations. SRS was engaged in providing energy services to industrial, commercial and institutional customers to help manage energy costs primarily in the southeastern United States. During 2004, SRS sold its subsidiary, Progress Energy Solutions (PES). With the disposition of PES, the Company exited this business area. Telecommunication operations provide broadband capacity services, dark fiber and wireless services in Florida and the eastern United States. In December 2003, PTC and Caronet, both wholly owned telecommunication subsidiaries of Progress Energy, and EPIK, a wholly owned subsidiary of Odyssey, contributed substantially all of their assets and transferred certain liabilities to PT LLC, a subsidiary of PTC. The accounts of PT LLC have been included in the Company's Consolidated Financial Statements since the transaction date. See additional discussion on the telecommunication business combination in Note 5A.

Other nonregulated business areas contributed segment losses of $38 million compared to losses of $24 million for the years ended December 31, 2004, and 2003, respectively. SRS recorded a net loss of $27 million for 2004 compared to a net loss of $6 million for 2003. The increased loss compared to the prior year is due primarily to the recording of the litigation settlement reached with San Francisco United School District (the District) related to civil proceedings. In June 2004, SRS reached a settlement with the District that settled all outstanding claims for approximately $43 million pre-tax ($29 million after-tax). The reduction in earnings due to the settlement was offset partially by a gain recognized on the sale of Progress Energy Solutions. Telecommunication operations recorded a net loss of $5 million in 2004 compared to a net profit of $2 million in 2003. The increase in losses compared to prior year is due to an increase in fixed costs, mainly depreciation expense, and professional fees related to the merger with EPIK. The increased losses at SRS and telecommunication operations were offset partially by a reduction in losses at the nonutility subsidiaries of PEC. The nonutility subsidiaries of PEC contributed segment losses of $6 million and $18 million for the years ended December 31, 2004, and 2003, respectively. Included in the 2003 segment losses is an investment impairment of $6 million after-tax on the Affordable Housing portfolio held by the nonutility subsidiaries of PEC (See Note 10B). A reduction in investment losses accounted for the remaining favorability compared to prior year.

Other nonregulated business areas contributed segment losses of $24 million in 2003 compared to $250 million for the year ended December 31, 2002. The 2002 segment losses include an asset impairment and other charges in the telecommunications business of $225 million after-tax. See discussion of impairments at Note 10 of the Consolidated Financial Statements.

CORPORATE SERVICES

Corporate Services (Corporate) includes the operations of the holding company, Progress Energy Service Company and other consolidating and nonoperating entities, as summarized below:

Income (Expense) (in millions)	2004	Change	2003	Change	2002
Other interest expense	**$ (270)**	$ 15	$ (285)	$ (10)	$ (275)
Contingent value obligations	**9**	18	(9)	(37)	28
Tax reallocation	**(37)**	1	(38)	18	(56)
Other income taxes	**102**	(22)	124	11	113
Other income (expense)	**(2)**	19	(21)	(16)	(5)
Segment loss	**$ (198)**	$ 31	$ (229)	$ (34)	$ (195)

The other interest expense decrease for 2004 compared to 2003 is partially due to the repayment of a $500 million unsecured note by the Holding Company on March 1, 2004, which reduced interest expense by $27 million pre-tax for 2004. This reduction was offset by interest no longer being capitalized due to the completion of construction in the CCO segment in 2003. Approximately $10 million ($6 million after-tax) was capitalized in 2003. No interest expense was capitalized during 2004. Interest expense increased $10 million in 2003 compared to 2002 due to a decrease of $9 million in the amount of interest capitalized related to the construction of plants by CCO which was completed in 2003.

Progress Energy issued 98.6 million contingent value obligations (CVOs) in connection with the acquisition of FPC in 2000. Each CVO represents the right to receive contingent payments based on the performance of four synthetic fuel facilities owned by Progress Energy. The payments, if any, are based on the net after-tax cash flows the facilities generate. At December 31, 2004, 2003 and 2002, the CVOs had a fair market value of approximately $13 million, $23 million and $14 million, respectively. Progress Energy recorded unrealized losses of $9 million for 2003 and an unrealized gain of $9 million and $28 million for 2004 and 2002, respectively, to record the changes in fair value of CVOs, which had average unit prices of $0.14, $0.23 and $0.14 at December 31, 2004, 2003 and 2002, respectively.

Progress Energy and its affiliates file a consolidated federal income tax return. The consolidated income tax of Progress Energy is allocated to subsidiaries in accordance with the Intercompany Income Tax Allocation Agreement (Tax Agreement). The Tax Agreement provided 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. Progress Energy tax benefits not related to acquisition interest expense are allocated to profitable subsidiaries, beginning in 2002, in accordance with a Public Utility Holding Company Act of 1935, as amended (PUHCA) order.

Other income taxes benefit decreased for 2004 compared to 2003 due primarily to increased taxes booked at the Holding Company of $21 million. Income taxes increased an additional $9 million at the Holding Company as a result of a reserve booked related to identified state tax deficiencies. Other income taxes benefit decreased for 2003 compared to 2002 primarily for the tax allocation to the profitable subsidiaries. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

Discontinued Operations

In 2002, the Company approved the sale of NCNG to Piedmont Natural Gas Company, Inc. As a result, the operating results of NCNG were reclassified to discontinued operations for all reportable periods. In September 2003, Progress Energy completed the sale of NCNG and ENCNG for net proceeds of approximately $450 million in September 2003. Progress Energy incurred a loss from discontinued operations of $8 million for 2003 compared with a loss of $24 million for 2002. During the year ended December 31, 2004, the Company recorded a reduction to the loss on the sale of NCNG of approximately $6 million related to deferred taxes (See Note 4E).

Cumulative Effect of Accounting Changes

In 2003, Progress Energy recorded adjustments for the cumulative effects of changes in accounting principles due to the adoption of several new accounting pronouncements. These adjustments totaled to a $21 million loss after-tax, which was due primarily to new Financial Accounting Standards Board (FASB) guidance related to the accounting for certain contracts. This guidance discusses whether the pricing in a contract that contains broad market indices qualifies for certain exceptions that would not require the contract to be recorded at its fair value. PEC Electric had a purchase power contract with Broad River LLC that did not meet the criteria for an exception, and a negative fair value adjustment was recorded in 2003 for $23 million after-tax (See Note 18A).

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Company prepared its Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States. In doing so, certain estimates were made that were critical in nature to the results of operations. The following discusses those significant estimates that may have a material impact on the financial results of the Company and are subject to the greatest amount of subjectivity. Senior management has discussed the development and selection of these critical accounting policies with the Audit Committee of the Company's Board of Directors.

Utility Regulation

As discussed in Note 8, the Company's regulated utilities segments are subject to regulation that sets the prices (rates) the Company is permitted to charge customers based on the costs that regulatory agencies determine the Company is permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by a nonregulated company. This rate-making process results in deferral of expense recognition and the recording of regulatory assets based on anticipated future cash inflows. As a result of the changing regulatory framework in each state in which the Company operates, a significant amount of regulatory assets has been recorded. The Company continually reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. Additionally, the state regulatory agencies often provide flexibility in the manner and timing of the depreciation of property, nuclear decommissioning costs and amortization of the regulatory assets. Note 8 provides additional information related to the impact of utility regulation on the Company.

Asset Impairments

As discussed in Note 10, the Company evaluates the carrying value of long-lived assets for impairment 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, the asset group held and used 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 if the asset group is to be disposed of, an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. A high degree of judgment is required in developing estimates related to these evaluations and various factors are considered, including projected revenues and cost and market conditions.

Due to the reduction in coal production at the Kentucky May coal mine, the Company evaluated its long-lived assets in 2003 and recorded an impairment of $17 million before tax ($11 million after tax). Fair value was determined based on discounted cash flows. During 2002, the Company recorded pre-tax long-lived asset impairments of $305 million related to its telecommunications business. The fair value of these assets was determined considering various factors, including a valuation study heavily weighted on a discounted cash flow methodology and using market approaches as supporting information.

The Company continually reviews its investments to determine whether a decline in fair value below the cost basis is other than temporary. In 2003, PEC's affordable housing investment (AHI) portfolio was reviewed and deemed to be impaired based on various factors, including continued operating losses of the AHI portfolio and management performance issues arising at certain properties within the AHI portfolio. As a result, PEC recorded an impairment of $18 million on a pre-tax basis during 2003. PEC also recorded an impairment of $3 million for a cost investment. During 2002, the Company recorded pre-tax impairments to its cost method investment in Interpath of $25 million. The fair value of this investment was determined considering various factors, including a valuation study heavily weighted on a discounted cash flow methodology and using market approaches as supporting information. These cash flows included numerous assumptions, including, the pace at which the telecommunications market would rebound. In the fourth quarter of 2002, the Company sold its remaining interest in Interpath for a nominal amount.

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, the Company is required to write-down capitalized costs to this level. The Company performs this ceiling test calculation every quarter. No write-downs were required in 2004, 2003 or 2002.

Goodwill

As discussed in Note 9, effective January 1, 2002, the Company adopted FASB Statement No. 142, "Goodwill and Other Intangible Assets," which requires that goodwill be tested for impairment at least annually and more frequently when indicators of impairment exist. The Company completed the initial transitional goodwill impairment test, which indicated that the Company's goodwill was not impaired as of January 1, 2002. The Company performed the annual goodwill impairment test for the CCO segment in the first quarters of 2004 and 2003, and the annual goodwill impairment test for the PEC Electric and PEF segments in the second quarters of 2004 and 2003, each of which indicated no impairment. If the fair values for the utility segments were lower by approximately 10%, there still would be no impact on the reported value of their goodwill. The carrying amounts of goodwill at December 31, 2004 and 2003, for reportable segments PEC Electric, PEF and CCO, are $1,922 million, $1,733 million and $64 million, respectively. In December 2003, $7 million in goodwill was acquired as part of Progress Telecommunications Corporation's partial acquisition of EPIK and was reported in the Corporate and Other segment. The Company 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.

Synthetic Fuels Tax Credits

As discussed in Note 23E, Progress Energy, through the Fuels business unit, owns facilities that produce synthetic fuel as defined under the Internal Revenue Code. The production and sale of the synthetic fuels from these facilities qualifies for tax credits under Section 29 if certain requirements are satisfied, including a requirement that the synthetic fuels differs significantly in chemical composition from the coal used to produce such synthetic fuels and that the fuel was produced from a facility placed in service before July 1, 1998. The amount of Section 29 credits that the Company is allowed to claim in any calendar year is limited by the amount of the Company's regular federal income tax liability. Synthetic fuels tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits on the Consolidated Balance Sheets. All of Progress Energy's synthetic fuel facilities have received PLRs from the IRS with respect to their operations, although these do not address placed-in-service date determinations. The PLRs do not limit the production on which synthetic fuel credits may be claimed. The current Section 29 tax credit program expires at the end of 2007. These tax credits are subject to review by the IRS, and if Progress Energy fails to prevail through the administrative or legal process, there could be a significant tax liability owed for previously taken Section 29 credits, with a significant impact on earnings and cash flows. Additionally, the ability to use tax credits currently being carried forward could be denied. See further discussion in "OTHER MATTERS" below, Note 23E and in the "Risk Factors" section.

Pension Costs

As discussed in Note 17A, Progress Energy maintains qualified noncontributory defined benefit retirement (pension) plans. The Company's reported costs are dependent on numerous factors resulting from actual plan experience and assumptions of future experience. For example, such costs are impacted by employee demographics, changes made to plan provisions, actual plan asset returns and key actuarial assumptions, such as expected long-term rates of return on plan assets and discount rates used in determining benefit obligations and annual costs.

Due to a slight decline in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate used to present value future benefit payments, the Company lowered the discount rate to 5.9% at December 31, 2004, which will increase the 2005 benefit costs recognized, all other factors remaining constant. Plan assets performed well in 2004, with returns of approximately 14%. That positive asset performance will result in decreased pension costs in 2005, all other factors remaining constant. Evaluations of the effects of these and other factors have not been completed, but the Company estimates that the total cost recognized for pensions in 2005 will be approximately $12 to $20 million higher than the amount recorded in 2004.

The Company has pension plan assets with a fair value of approximately $1.8 billion at December 31, 2004. The Company's expected rate of return on pension plan assets is 9.25%. The Company reviews this rate on a regular basis. Under Statement of Financial Accounting Standards No. 87, "Employer's Accounting for Pensions" (SFAS No. 87), the expected rate of return used in pension cost recognition is a long-term rate of return; therefore, the Company would adjust that return only if its fundamental assessment of the debt and equity markets changes or its investment policy changes significantly. The Company believes that its pension plans' asset investment mix and historical performance support the long-term rate of 9.25% being used. The Company did not adjust the rate in response to short-term market fluctuations such as the abnormally high market return levels of the latter 1990s, recent years' market declines and the market rebound in 2003 and 2004. A 0.25% change in the expected rate of return for 2004 would have changed 2004 pension costs by approximately $4 million.

Another factor affecting the Company's pension costs, and sensitivity of the costs to plan asset performance, is its selection of a method to determine the market-related value of assets, i.e., the asset value to which the 9.25% expected long-term rate of return is applied. SFAS No. 87 specifies that entities may use either fair value or an averaging method that recognizes changes in fair value over a period not to exceed five years, with the method selected applied on a consistent basis from year to year. The Company has historically used a five-year averaging method. When the Company acquired Florida Progress Corporation (Florida Progress) in 2000, it retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets. Changes in plan asset performance are reflected in pension costs sooner under the fair value method than the five-year averaging method, and, therefore, pension costs tend to be more volatile using the fair value method. For example, in 2004 the expected return for assets subject to the averaging method was 2% lower than in 2003, whereas the expected return for assets subject to the fair value method was 24% higher than in 2003. Approximately 50% of the Company's pension plan assets is subject to each of the two methods.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Progress Energy is a registered holding company and, as such, has no operations of its own. The Company's primary cash needs at the holding company level are its common stock dividend and interest expense and principal payments on its $4.3 billion of senior unsecured debt. The ability to meet these needs is dependent on the earnings and cash flows of its two electric utilities and nonregulated subsidiaries, and the ability of those subsidiaries to pay dividends or repay funds to Progress Energy.

Other significant cash requirements of the Company arise primarily from the capital-intensive nature of its electric utility operations and expenditures for its diversified businesses, primarily those of the Fuels segment.

The Company relies upon its operating cash flow, primarily generated by its two regulated electric utility subsidiaries, commercial paper and bank facilities, and its ability to access long-term debt and equity capital markets for sources of liquidity.

The majority of the Company's operating costs are related to its two regulated electric utilities, and a significant portion of these costs is recovered from customers through fuel and energy cost recovery clauses.

As a registered holding company under Public Utility Holding Company Act of 1935 (PUHCA), Progress Energy obtains approval from the SEC for the issuance and sale of securities as well as the establishment of intercompany extensions of credit (utility and nonutility money pools). PEC and PEF participate in the utility money pool, which allows the two utilities to lend and borrow between each other. A nonutility money pool allows Progress Energy's nonregulated operations to lend and borrow funds among each other. Progress Energy can lend money to the utility and nonutility money pools but cannot borrow funds.

Cash from operations, asset sales and the issuance of common stock are expected to fund capital expenditures and common dividends for 2005. Any excess cash proceeds would be used to reduce debt. To the extent necessary, short- and long-term debt may also be used as a source of liquidity.

The Company believes its internal and external liquidity resources will be sufficient to fund its current business plans. Risk factors associated with commercial paper backup credit facilities and credit ratings are discussed below and in the "Risk Factors" section of this report.

The following discussion of the Company's liquidity and capital resources is on a consolidated basis.

HISTORICAL FOR 2004 AS COMPARED TO 2003 AND 2003 AS COMPARED TO 2002

Cash Flows from Operations

Cash from operations is the primary source used to meet operating requirements and capital expenditures. Net cash provided by operating activities from continuing operations for the three years ending December 31, 2004, 2003 and 2002 were $1.6 billion, $1.7 billion and $1.6 billion, respectively.

Cash from operating activities for 2004 when compared with 2003 decreased $117 million, as the net result of the impact of hurricane costs, partially offset by the impact of an under-recovery of fuel costs in 2003. The increase in cash from operating activities for 2003 when compared with 2002 is largely the result of improved operating results at PEC.

During the third quarter of 2004, four hurricanes struck significant portions of the Company's service territories, with the most significant impact on PEF's territory. Restoration of the Company's systems from storm-related damage cost an estimated $398 million. PEC's cost totaled $13 million, of which $12 million was charged to O&M and $1 million was charged to capital. PEF's cost totaled $385 million, of which $338 million was charged to Storm Damage Reserve pursuant to a regulatory order and $47 million was charged to capital. On November 2, 2004, PEF filed a petition with the Florida Public Service Commission (FPSC) to recover $252 million of storm costs plus interest from retail rate payers over a two-year period (See Note 3).

Progress Energy is allowed to recover fuel costs incurred by PEC and PEF through their respective fuel cost recovery surcharges. Fuel price volatility can lead to over- or under-recovery of fuel costs, as changes in fuel prices are not immediately reflected in fuel surcharges due to regulatory lag in setting the surcharges. As a result, fuel price volatility can be both a source of and a drag on liquidity resources, depending on what phase of the cycle of price volatility the Company is experiencing. In addition, in 2004 PEF agreed with the FPSC to use a two-year period to determine the surcharge for the underrecovered fuel costs incurred in 2004 (See Note 8C).

Investing Activities

Net cash used in investing activities for the three years ending December 31, 2004, 2003 and 2002 were $0.9 billion, $1.5 billion and $2.2 billion, respectively.

Utility property additions for the Company's regulated electric operations were $1.0 billion or approximately 75% of consolidated capital expenditures in 2004 and $1.0 billion or approximately 58% of consolidated capital expenditures in 2003, excluding proceeds from asset sales. Capital expenditures for the regulated electric operations are primarily for normal construction activity and ongoing capital expenditures related to environmental compliance programs. Capital expenditures for the nonregulated operations are primarily for natural gas development activities and normal construction activity.

Excluding proceeds from sales of subsidiaries and other investments, cash used in investing activities decreased approximately $887 million in 2004 when compared with 2003. The decrease is due primarily to the acquisition of a nonregulated generation contract and acquisition of gas assets in 2003 and net proceeds from short-term investments in 2004, compared to net purchases of short-term investments in 2003.

Excluding proceeds from sales of subsidiaries and other investments, cash used in investing activities was $2.1 billion in 2003, down approximately $119 million when compared with 2002. The decrease is due primarily to lower utility property additions due to completion of Hines 2 construction at PEF and lower acquisitions of nonregulated assets.

During 2004, sales of subsidiaries and other investments primarily included proceeds from the sale of Railcar Ltd. assets of approximately $75 million and proceeds of approximately $251 million related to the sale of natural gas assets in the Forth Worth basin of Texas. Progress Energy used the proceeds from these sales to reduce indebtedness, including $241 million to pay off the Progress Genco Ventures, LLC, bank facility.

During 2003, the Company realized approximately $450 million of net cash proceeds from the sale of NCNG and ENCNG. The Company also received net proceeds of approximately $97 million in October 2003 for the sale of its Mesa gas properties in Colorado. Progress Energy used the proceeds from these sales to reduce indebtedness, primarily commercial paper, then outstanding.

During 2003, the Company acquired approximately 200 natural gas-producing wells for a cash purchase price of $168 million. The Company also acquired a long-term full-requirements power supply agreement with Jackson Electric Membership Corporation for a cash payment of $188 million.

During 2002, the Company purchased two electric generation projects for a cash purchase price of $348 million.

Financing Activities

Net cash (used in) provided by financing activities for the three years ending December 31, 2004, 2003 and 2002 were $(720), $(192) million and $581 million, respectively. See Note 13 for details of debt and credit facilities.

For 2004 and 2003, cash from operations exceeded net cash used in investing activities by $735 million and $178 million, respectively, due primarily to asset sales, which allowed for a net decrease in cash provided by financing activities. For 2002, net cash used in investing activity exceeded cash from operations by $574 million, which resulted in net cash from financing activities of $581 million.

In addition to the financing activities discussed under "Overview," the financing activities of the Company included:

2005

- In January 2005, the Company used proceeds from the issuance of commercial paper to pay off $260 million of revolving credit agreement (RCA) loans.
- On January 31, 2005, Progress Energy, Inc. entered into a new $600 million revolving credit agreement, which expires December 30, 2005. This facility was added to provide additional liquidity during 2005 due in part to the uncertainty of the timing of storm restoration cost recovery from the hurricanes in Florida during 2004. The credit agreement includes a defined maximum total debt to total capital ratio of 68% and a minimum interest coverage ratio of 2.5 to 1. The credit agreement also contains various cross-default and other acceleration provisions. On February 4, 2005, $300 million was drawn under the new facility to reduce commercial paper and pay off the remaining amount of RCA loans outstanding.
- In March 2005, Progress Energy, Inc.'s five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65% to 68% in anticipation of the potential impacts of proposed accounting rules for uncertain tax positions. See Notes 2 and 23E.

- During the fourth quarter of 2004, Progress Energy and its subsidiaries PEC and PEF borrowed a net total of $475 million under certain revolving credit facilities. The borrowed funds were used to pay off maturing commercial paper and for other cash needs. A summary of RCA loans and available capacity as of December 31, 2004, is as follows:

(in millions) Company	Description	Total	Outstanding	Available
Progress Energy, Inc.	5-Year (expiring 8/5/09)	$ 1,130	$ 160	$ 970
Progress Energy Carolinas, Inc.	364-Day (expiring 7/27/05)	165	90	75
Progress Energy Carolinas, Inc.	3-Year (expiring 7/31/05)	285	–	285
Progress Energy Florida, Inc.	364-Day (expiring 3/29/05)	200	170	30
Progress Energy Florida, Inc.	3-Year (expiring 4/01/06)	200	55	145
Less: amounts reserved(a)		–	–	(574)
Total credit facilities		$ 1,980	$ 475	$ 931

(a) To the extent amounts are reserved for commercial paper outstanding or backing letters of credit, they are not available for additional borrowings.

- On December 17, 2004, the Company used proceeds from the sale of natural gas assets to extinguish Progress Genco Ventures, LLC's $241 million bank facility (See Note 13D).

- Progress Energy took advantage of favorable market conditions and entered into a new $1.1 billion five-year line of credit, effective August 5, 2004, and expiring August 5, 2009. This facility replaced Progress Energy's $250 million 364-day line of credit and its three-year $450 million line of credit, which were both scheduled to expire in November 2004.

- On July 28, 2004, PEC extended its $165 million 364-day line of credit, which was scheduled to expire on July 29, 2004. The line of credit will expire on July 27, 2005.

- On July 1, 2004, PEF paid at maturity $40 million 6.69% Medium-Term Notes Series B with commercial paper proceeds and cash from operations.

- On April 30, 2004, PEC redeemed $35 million of Darlington County 6.6% Series Pollution Control Bonds at 102.5% of par, $2 million of New Hanover County 6.3% Series Pollution Control Bonds at 101.5% of par, and $2 million of Chatham County 6.3% Series Pollution Control Bonds at 101.5% of par with cash from operations.

- On March 1, 2004, Progress Energy used available cash and proceeds from the issuance of commercial paper to pay at maturity $500 million 6.55% senior unsecured notes. Cash and commercial paper capacity for this retirement was created primarily from proceeds of the sale of assets in 2003.

- On February 9, 2004, Progress Capital Holdings, Inc., paid at maturity $25 million 6.48% medium term notes with available cash from operations.

- On January 15, 2004, PEC paid at maturity $150 million 5.875% First Mortgage Bonds with commercial paper proceeds. On April 15, 2004, PEC also paid at maturity $150 million 7.875% First Mortgage Bonds with commercial paper proceeds and cash from operations.

- For 2004, the Company issued approximately 1 million shares of its common stock for approximately $73 million in net proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans, net of purchases of restricted shares. For 2004, the dividends paid on common stock were approximately $558 million.

2003

- Progress Energy obtained a three-year financing order, allowing it to issue up to $2.8 billion of long-term securities, $1.5 billion of short-term debt, and $3 billion in parent guarantees. Progress Energy issued approximately 8 million shares of common stock for approximately $304 million in net proceeds from its Investor Plus Stock Purchase Plan and its employee benefit plans, net of purchases of restricted shares. For 2003, the dividends paid on common stock were approximately $541 million.

- PEC redeemed $250 million and issued $600 million in first mortgage bonds.

- PEF redeemed $250 million, issued $950 million and paid at maturity $180 million in first mortgage bonds. PEF also paid at maturity $35 million in medium-term notes.

- Progress Capital Holdings, Inc., paid at maturity $58 million in medium-term notes.

- Progress Genco Ventures, LLC, terminated its $50 million working capital credit facility. Under its related construction facility, Genco had drawn $241 million at December 31, 2003.

2002

- Progress Energy issued $800 million in senior unsecured notes. Progress Energy issued approximately 2 million shares representing approximately $86 million in proceeds from its Investor Plus Stock Purchase Plan and its employee benefit plans.

- PEC issued and redeemed $500 million in senior unsecured notes and $48.5 million in pollution control obligations. PEC also redeemed $150 million and paid at maturity $100 million in first mortgage bonds.

- PEF issued and redeemed $241 million in pollution control obligations and paid at maturity $30 million in medium-term notes.

- Progress Capital Holdings, Inc., paid at maturity $50 million in medium-term notes.

- Progress Genco Ventures, LLC, obtained a $440 million bank facility, including $50 million for working capital. During the year, $130 million of the facility was terminated. The amount outstanding at December 31, 2002, was $225 million.

- In November 2002, the Company issued 14.7 million shares of common stock for net cash proceeds of approximately $600 million, which were primarily used to retire commercial paper. For 2002, the dividends paid on common stock were approximately $480 million.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

The Company's two electric utilities produced over 100% of consolidated cash from operations in 2004. It is expected that the two electric utilities will continue to produce a majority of the consolidated cash flows from operations over the next several years as its nonregulated investments, primarily generation assets, improve asset utilization and increase their operating cash flows.

PEF notified the FPSC in January 2005 of its intent to file for an increase in its base rates effective January 1, 2006. If approved by the FPSC, an increase in PEF's base rates would increase future operating cash flows. PEF has faced significant cost increases over the past decade and expects its operational costs to continue to increase. These costs include the costs associated with completion of the Hines 3 generation facility, extraordinary hurricane damage costs including capital costs not expected to be directly recoverable, the need to replenish the depleted storm reserve and the expected infrastructure investment necessary to meet high customer expectations, coupled with the demands placed on PEF as a result of strong customer growth. If the FPSC does not approve PEF's request to increase base rates, the Company's results of operations and financial condition could be negatively impacted. The Company cannot predict the outcome of this matter. Related risks are described in more detail in the "Risk Factors" section.

In addition, Fuels' synthetic fuel operations do not currently produce positive operating cash flow due to the difference in timing of when tax credits are recognized for financial reporting purposes and when tax credits are realized for tax purposes. See Note 23E for further discussion.

Capital Expenditures

Total cash from operations provided the funding for the Company's capital expenditures, including property additions, nuclear fuel expenditures and diversified business property additions during 2004, excluding proceeds from asset sales of $366 million.

As shown in the table below, Progress Energy expects the majority of its capital expenditures to be incurred at its regulated operations. See Note 8F for a discussion of expected impacts on future capital expenditures due to changes in capitalization practice for regulated operations. The Company anticipates its regulated capital expenditures will increase in 2005 due to increased spending on Clean Air initiatives. Forecasted nonregulated expenditures relate primarily to Progress Fuels and its gas operations, mainly for drilling new wells.

	Actual	Forecasted		
(in millions)	**2004**	2005	2006	2007
Regulated capital expenditures	**$ 998**	$ 1,030	$ 1,040	$ 1,090
Nuclear fuel expenditures	**101**	120	90	150
AFUDC – borrowed funds	**(6)**	(10)	(10)	(10)
Nonregulated capital expenditures	**236**	190	180	190
Total	**$ 1,329**	$ 1,330	$ 1,300	$ 1,420

Regulated capital expenditures in the table above include total expenditures from 2005 through 2006 of approximately $65 million expected to be incurred at PEC fossil-fueled electric generating facilities to comply with Section 110 of the Clean Air Act, referred to as the NOx SIP Call.

The Company also expects to incur expenditures of approximately $15 million ($10 million at PEC and $5 million at PEF) from 2005 through 2007 and additional expenditures of approximately $70 million to $100 million ($10 million to $20 million at PEC and $60 million to $80 million at PEF) from 2008 through 2009 for compliance with the Section 316(b) requirements of the Clean Water Act (See Note 22).

In June 2002, legislation was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from coal-fired power plants. PEC expects its capital costs to meet these emission targets will be approximately $895 million by 2013. For the years 2005 through 2007, the Company expects to incur approximately $475 million of total capital costs associated with this legislation, which is included in the table above (See Note 22).

All projected capital and investment expenditures are subject to periodic review and revision and may vary significantly depending on a number of factors including, but not limited to, industry restructuring, regulatory constraints, market volatility and economic trends.

Other Cash Needs

As of December 31, 2004, on a consolidated basis, the Company had $349 million of long-term debt maturing in 2005. Progress Energy expects to pay these maturities using funds from operations, issuance of new long-term debt, commercial paper borrowings and/or issuance of new equity securities.

In 2006, $800 million of Progress Energy senior unsecured notes will mature. The Company expects to fund the maturity using proceeds from the sale of the Progress Rail subsidiary, issuance of new long-term debt, commercial paper borrowings and/or issuance of new equity securities.

During the fourth quarter of 2004, Progress Energy announced the launch of a new cost management initiative aimed at achieving nonfuel O&M expense reductions of $75 million to $100 million annually by the end of 2007. In connection with this cost management initiative, the Company expects to incur one-time pre-tax charges of approximately $130 million. Approximately $30 million of that amount relates to payments for severance benefits, which will be recognized in the first quarter of 2005 and paid over time. The remaining approximately $100 million will be recognized in the second quarter of 2005 and relates primarily to postretirement benefits that will be paid over time to those eligible employees who elect to participate in the voluntary enhanced retirement program (See Note 24).

Credit Facilities

At December 31, 2004, the Company and its subsidiaries had committed lines of credit and outstanding balances as shown in the table in Note 13. All of the credit facilities supporting the credit were arranged through a syndication of financial institutions. There are no bilateral contracts associated with these facilities.

The Company's financial policy precludes issuing commercial paper in excess of its supporting lines of credit. At December 31, 2004, the Company had $424 million of commercial paper outstanding, $150 million reserved for backing of letters of credit and an additional $475 million drawn directly from the credit facilities, leaving $931 million available for issuance or drawdown. In addition, the Company has requirements to pay minimal annual commitment fees to maintain its credit facilities. At December 31, 2003, the Company had $4 million of commercial paper outstanding. The Company expects to continue to use commercial paper issuances as a source of liquidity as long as it maintains its current short-term ratings.

All of the credit facilities include a defined maximum total debt-to-total capital ratio (leverage) and coverage ratios. The Company is in compliance with these covenants at December 31, 2004. See Note 13 for a discussion of the credit facilities' financial covenants, material adverse change clause provisions and cross-default provisions. At December 31, 2004, the calculated ratios for the companies, pursuant to the terms of the agreements, are as disclosed in Note 13.

Both PEC and PEF plan to enter into new five-year lines of credit in 2005 to replace their existing credit facilities.

The Company has on file with the SEC a shelf registration statement under which senior notes, junior debentures, common and preferred stock and other trust preferred securities are available for issuance by the Company. At December 31, 2004, the Company had approximately $1.1 billion available under this shelf registration.

Progress Energy and PEF each have an uncommitted bank bid facility authorizing each of them to borrow and reborrow, and have loans outstanding at any time, up to $300 million and $100 million, respectively. At December 31, 2004, there were no outstanding loans against these facilities.

PEC currently has on file with the SEC a shelf registration statement under which it can issue up to $900 million of various long-term securities. PEF currently has on file registration statements under which it can issue an aggregate of $750 million of various long-term debt securities.

Both PEC and PEF can issue First Mortgage Bonds under their respective First Mortgage Bond indentures. At December 31, 2004, PEC and PEF could issue up to $2.9 billion and $3.7 billion, respectively, based on property additions and $2.2 billion and $176 million, respectively, based upon retirements.

The following table shows Progress Energy's and Progress Energy Carolinas' capital structure at December 31:

	Progress Energy		PEC	
	2004	2003	**2004**	2003
Common stock	**41.7%**	40.5%	**47.1%**	48.2%
Preferred stock and minority interest	**0.7%**	0.7%	**0.9%**	0.9%
Total debt	**57.6%**	58.8%	**52.0%**	50.9%

The amount and timing of future sales of company securities will depend on market conditions, operating cash flow, asset sales and the specific needs of the Company. The Company may from time to time sell securities beyond the amount needed to meet capital requirements in order to allow for the early redemption of long-term debt, the redemption of preferred stock, the reduction of short-term debt or for other general corporate purposes.

Credit Rating Matters

The major credit rating agencies have currently rated the Company's securities as follows:

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Progress Energy, Inc.			
Outlook	Negative	Negative	Stable
Corporate credit rating	n/a	BBB	n/a
Senior unsecured debt	Baa2	BBB-	BBB-
Commercial paper	P-2	A-3	n/a
Progress Energy Carolinas, Inc.			
Corporate credit rating	n/a	BBB	n/a
Commercial paper	P-2	A-3	F2
Senior secured debt	A3	BBB	A-
Senior unsecured debt	Baa1	BBB	BBB+
Progress Energy Florida, Inc.			
Corporate credit rating	n/a	BBB	n/a
Commercial paper	P-2	A-3	F2
Senior secured debt	A2	BBB	A-
Senior unsecured debt	A3	BBB	BBB+
FPC Capital I			
Preferred stock*	Baa2	BB+	n/a
Progress Capital Holdings, Inc.			
Senior unsecured debt*	Baa1	BBB-	n/a

*Guaranteed by Florida Progress Corporation.

These ratings reflect the current views of these rating agencies, and no assurances can be given that these ratings will continue for any given period of time. However, the Company monitors its financial condition as well as market conditions that could ultimately affect its credit ratings.

On February 11, 2005, Moody's credit rating agency announced that it lowered the ratings of PEF, Progress Capital Holdings and FPC Capital Trust I and changed their rating outlooks to stable from negative. Moody's affirmed the ratings of Progress Energy and PEC. The rating outlooks continue to be stable at PEC and negative at Progress Energy. Moody's stated that it took this action primarily due to declining cash flow coverages and rising leverage, higher O&M costs, uncertainty regarding the timing of hurricane cost recovery, regulatory risks associated with the upcoming rate case in Florida and ongoing capital requirements to meet Florida's growing demand.

On October 19, 2004, S&P changed Progress Energy's outlook from stable to negative. S&P cited the uncertainties regarding the timing of the recovery of hurricane costs, the Company's debt reduction plans and the IRS audit of the Company's Earthco synthetic fuels facilities as the reasons for the change in outlook. On October 25, 2004, S&P reduced the short-term debt rating of Progress Energy, PEC and PEF to A-3 from A-2, as a result of their change in outlook discussed above.

On October 20, 2004, Moody's changed its outlook for Progress Energy from stable to negative and placed the ratings of PEF under review for possible downgrade. PEC's ratings were affirmed by Moody's.

Moody's cited the following reasons for its change in the outlook for Progress Energy: financial ratios that are weak for its current rating category; rising O&M, pension, benefit and insurance costs; and delays in executing its deleveraging plan. With respect to PEF, Moody's cited declining cash flow coverages and rising leverage over the last several years, expected funding needs for a large capital expenditure program, risks with regard to its upcoming 2005 rate case and the timing of hurricane cost recovery as reasons for putting its ratings under review.

The changes by S&P and Moody's do not trigger any debt or guarantee collateral requirements, nor do they have any material impact on the overall liquidity of Progress Energy or any of its affiliates. To date, Progress Energy's, PEC's and PEF's access to the commercial paper markets has not been materially impacted by the rating agencies' actions. However, the changes have increased the interest rate incurred on its short-term borrowings by 0.25% to 0.875%.

If Standard & Poor's lowers Progress Energy's senior unsecured rating one ratings category to BB+ from its current rating, it would be a noninvestment grade rating. The effect of a noninvestment grade rating would primarily be to increase borrowing costs. The Company's liquidity would essentially remain unchanged, as the Company believes it could borrow under its revolving credit facilities instead of issuing commercial paper for its short-term borrowing needs. However, there would be additional funding requirements of approximately $450 million due to ratings triggers embedded in various contracts, as more fully described below under "Guarantees" and "Risk Factors."

The Company and its subsidiaries' debt indentures and credit agreements do not contain any "ratings triggers," which would cause the acceleration of interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, the Company and/or its subsidiaries may be subject to increased interest costs on the credit facilities backing up the commercial paper programs. In addition, the Company and its subsidiaries have certain contracts that have provisions triggered by a ratings downgrade to a rating below investment grade. These contracts include counterparty trade agreements, derivative contracts, certain Progress Energy guarantees and various types of third-party purchase agreements.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

The Company's off-balance sheet arrangements and contractual obligations are described below.

Guarantees

As a part of normal business, Progress Energy and certain wholly owned subsidiaries enter into various agreements providing future financial or performance assurances to third parties that are outside the scope of Financial Accounting Standards Board (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 and subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. The Company's guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. The Company's guarantees also include standby letters of credit, surety bonds and guarantees in support of nuclear decommissioning. At December 31, 2004, the Company had issued $1.3 billion of guarantees for future financial or performance assurance. Management does not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

The majority of contracts supported by the guarantees contain provisions that trigger guarantee obligations based on downgrade events to below investment grade (below BBB- or Baa3), ratings triggers, monthly netting of exposure and/or payments and offset provisions in the event of a default. The recent outlook changes from S&P and Moody's do not trigger any guarantee obligations. As of December 31, 2004, if the guarantee obligations were triggered, the maximum amount of liquidity requirements to support ongoing operations within a 90-day period, associated with guarantees for the Company's nonregulated portfolio and power supply agreements was $450 million. The Company would meet this obligation with cash or letters of credit.

As of December 31, 2004, Progress Energy had guarantees issued on behalf of third parties of approximately $10 million. See Note 23D for a discussion of guarantees in accordance with FIN No. 45.

Market Risk and Derivatives

Under its risk management policy, the Company may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 18 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

Contractual Obligations

The Company is party to numerous contracts and arrangements obligating it to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. Amounts in the following table are estimated based upon contractual terms and actual amounts will likely differ from amounts presented below. Further disclosure regarding the Company's contractual obligations is included in the respective notes. The Company takes into consideration the future commitments when assessing its liquidity and future financing needs. The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2004, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (a) (See Note 13)	$ 9,942	$ 349	$ 1,637	$ 1,387	$ 6,569
Interest payments on long-term debt and interest rate derivatives (b)	3,064	301	489	423	1,851
Capital lease obligations (See Note 23C)	50	4	8	7	31
Operating leases (See Note 23C)	597	66	113	112	306
Fuel and purchased power (c) (See Note 23A)	13,010	2,692	3,088	1,346	5,884
Other purchase obligations (See Note 23A)	633	151	134	80	268
NC Clean Air capital commitments (See Note 22)	764	170	297	143	154
Other commitments (d)(e)	243	42	70	26	105
Total	$ 28,303	$ 3,775	$ 5,836	$ 3,524	$ 15,168

a. The Company's maturing debt obligations are generally expected to be refinanced with new debt issuances in the capital markets. However, the Company does plan to annually reduce its debt to total capitalization leverage by one to two percentage points over the next few years through selected asset sales, free cash flow and increased equity from retained earnings and ongoing equity issuances.

b. Interest payments on long-term debt and interest rate derivatives are based on the interest rate effective as of December 31, 2004, and the LIBOR forward curve as of December 31, 2004, respectively.

c. Fuel and purchased power commitments represent the majority of the Company's remaining future commitments after its debt obligations. Essentially all of the Company's fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.

d. In 2008, PEC must begin transitioning amounts currently retained internally to its external decommissioning funds. The transition of $131 million must be complete by December 31, 2017, and at least 10% must be transitioned each year.

e. The Company has certain future commitments related to four synthetic fuel facilities purchased that provide for contingent payments (royalties) through 2007 (See Note 23B).

OTHER MATTERS

Synthetic Fuels Tax Credits

The Company has substantial operations associated with the production of coal-based synthetic fuels. The production and sale of these products qualifies for federal income tax credits so long as certain requirements are satisfied. These operations are subject to numerous risks.

Although the Company believes that it operates its synthetic fuel facilities in compliance with applicable legal requirements for claiming the credits, its four Earthco facilities are under audit by the IRS. IRS field auditors have taken an adverse position with respect to the Company's compliance with one of these legal requirements, and if the Company fails to prevail with respect to this position, it could incur significant liability and/or lose the ability to claim the benefit of tax credits carried forward or generated in the future. Similarly, the Financial Accounting Standards Board may issue new accounting rules that would require that uncertain tax benefits (such as those associated with the Earthco plants) be probable of being sustained in order to be recorded on the financial statements; if adopted, this provision could have an adverse financial impact on the Company.

The Company's ability to utilize tax credits is dependent on having sufficient tax liability. Any conditions that negatively impact the Company's tax liability, such as weather, could also diminish the Company's ability to utilize credits, including those previously generated, and the synthetic fuel is generally not economical to produce absent the credits. Finally, the tax credits associated with synthetic fuels may be phased out if market prices for crude oil exceed certain prices.

The Company's synthetic fuel operations and related risks are described in more detail in Note 23E and in the "Risk Factors" section.

Hurricane Costs

Hurricanes Charley, Frances, Ivan and Jeanne struck significant portions of the Company's service territories during the third quarter of 2004, significantly impacting PEF's territory. As of December 31, 2004, restoration of the Company's systems from hurricane-related damage was estimated at $398 million. PEC incurred restoration costs of $13 million, of which $12 million was charged to operation and maintenance expense and $1 million was charged to capital expenditures. PEF had estimated total costs of $385 million, of which $47 million was charged to capital expenditures, and $338 million was charged to the storm damage reserve pursuant to a regulatory order.

In accordance with a regulatory order, PEF accrues $6 million annually to a storm damage reserve and is allowed to defer losses in excess of the accumulated reserve for major storms. Under the order, the storm reserve is charged with operation and maintenance expenses related to storm restoration and with capital expenditures related to storm restoration that are in excess of expenditures assuming normal operating conditions. As of December 31, 2004, $291 million of hurricane restoration costs in excess of the previously recorded storm reserve of $47 million had been classified as a regulatory asset recognizing the probable recoverability of these costs. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail ratepayers over a two-year period. Storm reserve costs of $13 million were attributable to wholesale customers. The Company has received approval from the FERC to amortize these costs consistent with recovery of such amounts in wholesale rates. PEF continues to review the restoration cost invoices received. Given that not all invoices have been received as of December 31, 2004, PEF will update its petition with the FPSC upon receipt and audit of all actual charges incurred. Hearings on PEF's petition for recovery of $252 million of storm costs filed with the FPSC are scheduled to begin on March 30, 2005.

On November 17, 2004, the Citizens of the State of Florida, by and through Harold McLean, Public Counsel, and the Florida Industrial Power Users Group (FIPUG), (collectively, Joint Movants), filed a Motion to Dismiss PEF's petition to recover the $252 million in storm costs. On November 24, 2004, PEF responded in opposition to the motion, which was also the FPSC staff's position in its recommendation to the Commission on December 21, 2004, that it should deny the Motion to Dismiss. On January 4, 2005, the Commission ruled in favor of PEF and denied the Joint Movant's Motion to Dismiss.

PEF's January 2005 notice to the FPSC of its intent to file for an increase in its base rates effective January 1, 2006, anticipates the need to replenish the depleted storm reserve balance and adjust the annual $6 million accrual in light of recent storm history to restore the reserve to an adequate level over a reasonable time period.

PEC does not have an ongoing regulatory mechanism to recover storm costs; therefore, hurricane restoration costs recorded in the third quarter of 2004 were charged to operations and maintenance expenses or capital expenditures based on the nature of the work performed. In connection with other storms, PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over a five-year period. PEC did not seek deferral of 2004 storm costs from the NCUC (See Note 8B).

Regulatory Environment and Matters

The Company's electric utility operations in North Carolina, South Carolina and Florida are regulated by the NCUC, the Public Service Commission of South Carolina (SCPSC) and the FPSC, respectively. The electric businesses are also subject to regulation by the FERC, the NRC and other federal and state agencies common to the utility business. In addition, the Company is subject to SEC regulation as a registered holding company under PUHCA. As a result of regulation, many of the fundamental business decisions, as well as the rate of return the electric utilities are permitted to earn, are subject to the approval of governmental agencies.

PEC and PEF continue to monitor any developments toward a more competitive environment and have actively participated in regulatory reform deliberations in North Carolina, South Carolina and Florida. Movement toward deregulation in these states has been affected by recent developments, including developments related to deregulation of the electric industry in other states. The Company expects the legislatures in all three states will continue to monitor the experiences of states that have implemented electric restructuring legislation. The Company cannot anticipate when, or if, any of these states will move to increase competition in the electric industry.

The retail rate matters affected by the regulatory authorities are discussed in detail in Notes 8B and 8C. This discussion identifies specific retail rate matters, the status of the issues and the associated effects to the Company's consolidated financial statements.

The regulatory authorities continue to evaluate issues related to the formation of Regional Transmission Organizations. The Company cannot predict the outcome of these matters on the Company's earnings, revenues or prices or the investments in GridSouth and GridFlorida (See Note 8D).

A FERC order issued in November 2001 on certain unaffiliated utilities' triennial market-based wholesale power rate authorization updates required certain mitigation actions that those utilities would need to take for sales/purchases within their control areas and required those utilities to post information on their Web sites regarding their power systems' status. As a result of a request for rehearing filed by certain market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. 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 believes it would experience in passing one of the interim screens, on August 12, 2004, PEC notified the FERC that it would revise its Market-based Rate tariff to restrict it to sales outside PEC's control area and file a new cost-based tariff for sales within PEC's control area that incorporates the FERC's default cost-based rate methodologies for sales of one year or less. PEC anticipates making this filing in the first quarter of 2005. Although the Company cannot predict the ultimate outcome of these changes, the Company does not anticipate that the current operations of PEC or PEF would be impacted materially if they were unable to sell power at market-based rates in their respective control areas.

Franchise Litigation

Three cities, with a total of approximately 18,000 customers, have litigation pending against PEF in various circuit courts in Florida. As previously reported, three other cities, with a total of approximately 30,000 customers, have subsequently settled their lawsuits with PEF and signed new, 30-year franchise agreements. The lawsuits principally seek (1) a declaratory judgment that the cities have the right to purchase PEF's electric distribution system located within the municipal boundaries of the cities, (2) a declaratory judgment that the value of the distribution system must be determined through arbitration, and (3) injunctive relief requiring PEF to continue to collect from PEF's customers, and remit to the cities, franchise fees during the pending litigation, and as long as PEF continues to occupy the cities' rights-of-way to provide electric service, notwithstanding the expiration of the franchise ordinances under which PEF had agreed to collect such fees. The circuit courts in those cases have entered orders requiring arbitration to establish the purchase price of PEF's electric distribution system within five cities. Two appellate courts have upheld those circuit court decisions and authorized the cities to determine the value of PEF's electric distribution system within the cities through arbitration.

Arbitration in one of the cases (with the 13,000-customer City of Winter Park) was completed in February 2003. That arbitration panel issued an award in May 2003 setting the value of PEF's distribution system within the City of Winter Park (the City) at approximately $32 million, not including separation and reintegration and construction work in progress, which could add several million dollars to the award. The panel also awarded PEF approximately $11 million in stranded costs, which, according to the award, decrease over time. In September 2003, Winter Park voters passed a referendum that would authorize the City to issue bonds of up to approximately $50 million to acquire PEF's electric distribution system. While the City has not yet definitively decided whether it will acquire the system, on April 26, 2004, the City Commission voted to proceed with the acquisition. The City sought and received wholesale power supply bids and on June 24, 2004, executed a wholesale power supply contract with PEF. On May 12, 2004, the City solicited bids to operate and maintain the distribution system and awarded a contract in January 2005. The City has indicated that its goal is to begin electric operations in June 2005. On February 10, 2005, PEF filed a petition with the Florida Public Service Commission to relieve the Company of its statutory obligation to serve customers in Winter Park on June 1, 2005, or at such time when the City is able to provide retail service. At this time, whether and when there will be further proceedings regarding the City of Winter Park cannot be determined.

Arbitration with the 2,500-customer Town of Belleair was completed in June 2003. In September 2003, the arbitration panel issued an award in that case setting the value of the electric distribution system within the Town at approximately $6 million. The panel further required the Town to pay to PEF its requested $1 million in separation and reintegration costs and $2 million in stranded costs. The Town has not yet decided whether it will attempt to acquire the system; however, on January 18, 2005, it issued a request for proposals for wholesale power supply and to operate and maintain the distribution system. Proposals are due in early March 2005. In February 2005, the Town Commission also voted to put the issue of whether to acquire the distribution system to a voter referendum on or before October 2, 2005. At this time, whether and when there will be further proceedings regarding the Town of Belleair cannot be determined.

Arbitration in the remaining city's litigation (the 1,500-customer City of Edgewood) has not yet been scheduled. On February 17, 2005, the parties filed a joint motion to stay the litigation for a 90-day period during which the parties will discuss potential settlement.

A fourth city (the 7,000-customer City of Maitland) is contemplating municipalization and has indicated its intent to proceed with arbitration to determine the value of PEF's electric distribution system within the City. Maitland's franchise expires in August 2005. At this time, whether and when there will be further proceedings regarding the City of Maitland cannot be determined.

As part of the above litigation, two appellate courts reached opposite conclusions regarding whether PEF must continue to collect from its customers and remit to the cities "franchise fees" under the expired franchise ordinances. PEF filed an appeal with the Florida Supreme Court to resolve the conflict between the two appellate courts. On October 28, 2004, the Court issued a decision holding that PEF must collect from its customers and remit to the cities franchise fees during the interim period when the city exercises its purchase option or executes a new franchise. The Court's decision should not have a material impact on the Company.

Legal

The Company is subject to federal, state and local legislation and court orders. These matters are discussed in detail in Note 23E. This discussion identifies specific issues, the status of the issues, accruals associated with issue resolutions and the associated exposures to the Company.

Nuclear

Nuclear generating units are regulated by the NRC. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit or some combination of these, depending upon its assessment of the severity of the situation, until compliance is achieved. The nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs and certain other modifications (See Notes 6 and 23E).

Environmental Matters

The Company is subject to federal, state and local regulations addressing air and water quality, hazardous and solid waste management and other environmental matters. These environmental matters are discussed in detail in Note 22. This discussion identifies specific environmental issues, the status of the issues, accruals associated with issue resolutions and the associated exposures to the Company. The Company accrues costs to the extent they are probable and can be reasonably estimated. It is reasonably possible that additional losses, which could be material, may be incurred in the future.

New Accounting Standards

See Note 2 for a discussion of the impact of new accounting standards.

PEC

The information required by this item is incorporated herein by reference to the following portions of Progress Energy's Management's Discussion and Analysis of Financial Condition and Results of Operations, insofar as they relate to PEC: RESULTS OF OPERATIONS; LIQUIDITY AND CAPITAL RESOURCES; FUTURE OUTLOOK and OTHER MATTERS.

The following Management's Discussion and Analysis and the information incorporated herein by reference contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review "Risk Factors" and "SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS" for a discussion of the factors that may impact any such forward-looking statements made herein.

RESULTS OF OPERATIONS

The results of operations for the PEC consolidated for the years ended December 31 are summarized in the table below. The results of operations for the PEC Electric segment are identical in all material respects between PEC and Progress Energy for all periods presented. The primary difference between the results of operations of the PEC Electric segment and the consolidated PEC results of operations relate to the nonelectric operations, as summarized below:

(in millions)	2004	2003	2002
PEC Electric income before cumulative effect	$ 464	$ 515	$ 513
Caronet net income (loss)	–	5	(79)
Other nonelectric net loss	(6)	(18)	(6)
Cumulative effect of accounting change	–	(23)	–
Earnings for common stock	$ 458	$ 479	$ 428

Caronet's results of operations for 2002 includes after-tax impairments of $87 million for other-than-temporary declines in the value of the assets of Caronet and Caronet's investment in Interpath (See Note 7A to the PEC Consolidated Financial Statements). The stock of Caronet was sold in December 2003 (See Note 1A to the PEC Consolidated Financial Statements).

The other nonelectric subsidiaries of PEC contributed segment losses of $6 million and $18 million for the years ended December 31, 2004 and 2003, respectively. The Other nonelectric results for 2003 include investment impairments of $6 million after-tax on the Affordable Housing portfolio held by the nonutility subsidiaries of PEC. (See Note 7B to the PEC Consolidated Financial Statements.) A reduction in investment losses accounted for the remaining favorability compared to prior year.

In 2003, PEC Electric recorded cumulative effects of changes in accounting principles due to the adoption of a new accounting pronouncement. This adjustment totaled to a $23 million loss due primarily to the new FASB guidance related to the accounting for the purchase power contract with Broad River LLC (See Note 13A to the PEC Consolidated Financial Statements).

Note 1D to the PEC Consolidated Financial Statements discusses its significant accounting policies. The most critical accounting policies and estimates that impact PEC's consolidated financial statements are the economic impacts of utility regulation and asset impairment policies, described in more detail in the Progress Energy Management's Discussion and Analysis section.

LIQUIDITY AND CAPITAL RESOURCES

Overview

PEC has primarily used a combination of unsecured notes, first mortgage bonds, pollution control bonds, commercial paper facilities and revolving credit agreements for liquidity needs in excess of cash provided by operations.

During 2004, PEC extended its $165 million 364-day line of credit to July 27, 2005 and PEC's three-year $285 million line of credit expires July 31, 2005.

As discussed above in the Progress Energy "Overview," in October 2004, S&P reduced the short-term debt rating of PEC to A-3 from A-2. As a result of the impact of these actions on PEC's ability to access the commercial paper markets, PEC has borrowed on its revolving credit agreements. As of December 31, 2004, the total amount of outstanding borrowings on PEC's revolving credit agreements was $90 million. The borrowed funds were used to pay off maturing commercial paper and for other cash needs.

The changes by S&P do not trigger any debt or guarantee collateral requirements, nor do they have any material impact on the overall liquidity of PEC. To date, PEC's access to the commercial paper markets has not been materially impacted by the rating agencies' actions. However, the changes have increased the interest rate incurred on its short-term borrowings by 0.25% to 0.875%.

PEC expects to have sufficient resources to meet its future obligations either through internally generated funds, its short term-term borrowing facilities or through the issuance of long-term debt.

HISTORICAL FOR 2004 AS COMPARED TO 2003 AND 2003 AS COMPARED TO 2002

In 2004, cash provided by operating activities decreased when compared to 2003. The decrease was caused primarily by a $89 million under-recovery of fuel costs and a $76 million decrease in payables to affiliates. In 2003, cash provided by operating activities increased when compared to 2002, largely as a result of improved operating results.

In 2004, cash used in investing activities decreased approximately $257 million in 2004 when compared with 2003. The decrease is primarily to net proceeds from short-term investments in 2004, compared to net purchases in 2003. The decrease is partially offset by an increase in capital expenditures, primarily related to increased spending for NC Clean Air legislation, and an increase in nuclear fuel additions.

See the discussion above for Progress Energy under "Financing Activities" for information regarding PEC's financing activities.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEC's estimated capital requirements for 2005, 2006 and 2007 are $650 million, $670 million and $680 million, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation and upgrade existing facilities. See Note 6E to the PEC Consolidated Financial Statements for a discussion of expected impacts on future capital expenditures due to changes in capitalization practice for PEC. PEC expects to fund its capital requirements primarily through internally generated funds. In addition, PEC has $450 million in credit facilities that support the issuance of commercial paper. Access to the commercial paper market and the utility money pool provide additional liquidity to help meet PEC's working capital requirements. PEC plans to enter into a new five-year line of credit in 2005 that will replace these two expiring facilities.

See Note 9 to the PEC Consolidated Financial Statements for information on PEC's available credit facilities at December 31, 2004.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

PEC's off-balance sheet arrangements and contractual obligations are described below.

Market Risk and Derivatives

Under its risk management policy, PEC may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 13 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

Contractual Obligations

PEC is party to numerous contracts and arrangements obligating it to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. Amounts in the following table are estimated based upon contractual terms and will likely differ from amounts presented below. Further disclosure regarding PEC's contractual obligations is included in the respective notes to the PEC Consolidated Financial Statements. PEC takes into consideration the future commitments when assessing its liquidity and future financing needs. The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2004, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (a) (See Note 9)	$ 3,069	$ 300	$ 200	$ 700	$ 1,869
Interest payments on long-term debt and interest rate derivatives (b)	1,342	150	285	207	700
Capital lease obligations (See Note 18B)	35	2	4	4	25
Operating leases (See Note 18B)	187	28	37	25	97
Fuel and purchased power (c) (See Note 18A)	3,427	786	1,098	431	1,112
Other purchase obligations (See Note 18A)	25	12	–	–	13
North Carolina clean air capital commitments (See Note 17)	764	170	297	143	154
Other commitments (d)	131	–	–	26	105
Total	$ 8,980	$ 1,448	$ 1,921	$ 1,536	$ 4,075

a. The Company's maturing debt obligations are generally expected to be refinanced with new debt issuances in the capital markets. However, the Company does plan to annually reduce its debt to total capitalization leverage by one to two percentage points over the next few years through selected asset sales, free cash flow and increased equity from retained earnings and ongoing equity issuances.
b. Interest payments on long-term debt and interest rate derivatives are based on the interest rate effective as of December 31, 2004, and the LIBOR forward curve as of December 31, 2004, respectively.
c. Fuel and purchased power commitments represent the majority of the Company's remaining future commitments after its debt obligations. Essentially all of the Company's fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.
d. In 2008, PEC must begin transitioning amounts currently retained internally to its external decommissioning funds. The transition of $131 million must be complete by December 31, 2017, and at least 10% must be transitioned each year.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Progress Energy, Inc.

Market risk represents the potential loss arising from adverse changes in market rates and prices. Certain market risks are inherent in the Company's financial instruments, which arise from transactions entered into in the normal course of business. The Company's primary exposures are changes in interest rates with respect to its long-term debt and commercial paper, and fluctuations in the return on marketable securities with respect to its nuclear decommissioning trust funds. The Company manages its market risk in accordance with its established risk management policies, which may include entering into various derivative transactions.

These financial instruments are held for purposes other than trading. The risks discussed below do not include the price risks associated with nonfinancial instrument transactions and positions associated with the Company's operations, such as purchase and sales commitments and inventory.

Interest Rate Risk

The Company manages its interest rate risks through the use of a combination of fixed and variable rate debt. Variable rate debt has rates that adjust in periods ranging from daily to monthly. Interest rate derivative instruments may be used to adjust interest rate exposures and to protect against adverse movements in rates.

The following tables provide information at December 31, 2004 and 2003, about the Company's interest rate risk-sensitive instruments. The tables present principal cash flows and weighted-average interest rates by expected maturity dates for the fixed and variable rate long-term debt and FPC obligated mandatorily redeemable securities of trust. The tables also include estimates of the fair value of the Company's interest rate risk-sensitive instruments based on quoted market prices for these or similar issues. For interest rate swaps and interest rate forward contracts, the tables present notional amounts and weighted-average interest rates by contractual maturity dates for 2005-2009 and thereafter and the fair value of the related hedges. Notional amounts are used to calculate the contractual cash flows to be exchanged under the interest rate swaps and the settlement amounts under the interest rate forward contracts. See Note 18 for more information on interest rate derivatives.

December 31, 2004 (dollars in millions)	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value December 31, 2004
Fixed rate long-term debt	$ 349	$ 908	$ 674	$ 827	$ 400	$ 5,399	$ 8,557	$ 9,454
Average interest rate	7.38%	6.78%	6.41%	6.27%	5.95%	6.55%	6.54%	
Variable rate long-term debt	–	$ 55	–	–	$ 160	$ 861	$ 1,076	$ 1,077
Average interest rate	–	2.95%	–	–	3.19%	1.70%	1.99%	
Debt to affiliated trust[(a)]	–	–	–	–	–	$ 309	$ 309	$ 312
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives:								
Pay variable /receive fixed	–	–	–	$ (100)	–	$ (50)	$ (150)	$ 3
Average pay rate	–	–	–	(b)	–	(b)	(b)	
Average receive rate	–	–	–	4.10%	–	4.65%	4.28%	
Interest rate forward contracts	$ 200	–	–	–	–	$ 131	$ 331	$ (2)
Average pay rate	3.07%	–	–	–	–	4.90%	3.79%	
Average receive rate	(c)	–	–	–	–	(b)	(b) (c)	

(a) FPC Capital I – Quarterly Income Preferred Securities.
(b) Rate is 3-month LIBOR, which was 2.56% at December 31, 2004.
(c) Rate is 1-month LIBOR, which was 2.40% at December 31, 2004.

December 31, 2003 (dollars in millions)	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value December 31, 2003
Fixed rate long-term debt	$ 868	$ 349	$ 909	$ 674	$ 827	$ 5,836	$ 9,463	$ 10,501
Average interest rate	6.67%	7.38%	6.78%	6.41%	6.27%	6.51%	6.55%	
Variable rate long-term debt	–	–	–	$ 241	–	$ 861	$ 1,102	$ 1,103
Average interest rate	–	–	–	3.04%	–	1.08%	1.51%	
Debt to affiliated trust[a]	–	–	–	–	–	$ 309	$ 309	$ 313
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives:								
Pay variable/receive fixed	–	–	$ (300)	$ (350)	$ (200)	–	$ (850)	$ (4)
Average pay rate			(b)	(b)	(b)		(b)	
Average receive rate			2.75%	3.35%	2.93%		3.04%	
Payer swaptions	–	–	–	–	$ 400	–	$ 400	$ 5
Average pay rate					4.75%			
Average receive rate					(b)			
Interest rate collars[c]	$ 65	–	–	$ 130	–	–	$ 195	$ (11)
Cap rate	6.00%			6.50%				
Floor rate	4.13%			5.13%				

(a) FPC Capital I – Quarterly Income Preferred Securities.
(b) Rate is 3-month LIBOR, which was 1.15% at December 31, 2003.
(c) Notional amount is varying with a maximum of $195 million, decreasing to $130 million after December 2004.

Marketable Securities Price Risk

The Company's electric utility subsidiaries maintain trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning their nuclear plants. These funds are primarily invested in stocks, bonds and cash equivalents, which are exposed to price fluctuations in equity markets and to changes in interest rates. The fair value of these funds was $1.044 billion and $938 million at December 31, 2004 and 2003, respectively. The Company actively monitors its portfolio by benchmarking the performance of its investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Company's regulated electric rates provide for recovery of these costs net of any trust fund earnings, and, therefore, fluctuations in trust fund marketable security returns do not affect the earnings of the Company.

Contingent Value Obligations Market Value Risk

In connection with the acquisition of FPC, the Company issued 98.6 million CVOs. Each CVO represents the right to receive contingent payments based on the performance of four synthetic fuel facilities purchased by subsidiaries of FPC in October 1999. The payments, if any, are based on the net after-tax cash flows the facilities generate. These CVOs are recorded at fair value, and unrealized gains and losses from changes in fair value are recognized in earnings. At December 31, 2004 and 2003, the fair value of these CVOs was $13 million and $23 million, respectively. A hypothetical 10% decrease in the December 31, 2004, market price would result in a $1 million decrease in the fair value of the CVOs.

Commodity Price Risk

The Company is exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related products marketed and purchased as a result of its ownership of energy-related assets. The Company's exposure to these fluctuations is significantly limited by the cost-based regulation of PEC and PEF. Each state commission allows electric utilities to recover certain of these costs through various cost recovery clauses to the extent the respective commission determines that such costs are prudent. Therefore, while there may be a delay in the timing between when these costs are incurred and when these costs are recovered from the ratepayers, changes from year to year have no material impact on operating results. In addition, many of the Company's long-term power sales contracts shift substantially all fuel responsibility to the purchaser. The Company also has oil price risk exposure related to synfuel tax credits. See discussion in Note 23E.

The Company uses natural gas hedging instruments to manage a portion of the market risk associated with fluctuations in the future sales price of the Company's natural gas. In addition, the Company may engage in limited economic hedging activity using natural gas and electricity financial instruments.

In 2004, PEF entered into derivative instruments related to its exposure to price fluctuations on fuel oil purchases. At December 31, 2004, the fair values of these 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. These instruments receive regulatory accounting treatment. Gains are recorded in regulatory liabilities and losses are recorded in regulatory assets.

Refer to Note 18 for additional information with regard to the Company's commodity contracts and use of derivative financial instruments.

The Company performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% increase or decrease in quoted market prices in the near term on the Company's derivative commodity instruments would not have had a material effect on the Company's consolidated financial position, results of operations or cash flows as of December 31, 2004.

PEC

PEC has certain market risks inherent in its financial instruments, which arise from transactions entered into in the normal course of business. PEC's primary exposures are changes in interest rates, with respect to long-term debt and commercial paper, and fluctuations in the return on marketable securities, with respect to its nuclear decommissioning trust funds.

The information required by this item is incorporated herein by reference to the Quantitative and Qualitative Disclosures About Market Risk insofar as it relates to PEC.

Interest Rate Risk

The following tables provide information at about PEC's interest rate risk sensitive instruments:

December 31, 2004 (dollars in millions)	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value December 31, 2004
Fixed rate long-term debt	$ 300	–	$ 200	$ 300	$ 400	$ 1,249	$ 2,449	$ 2,686
Average interest rate	7.50%	–	6.80%	6.65%	5.95%	6.13%	6.38%	
Variable rate long-term debt	–	–	–	–	–	$ 620	$ 620	$ 621
Average interest rate	–	–	–	–	–	1.71%	1.71%	
Interest rate forward contracts	–	–	–	–	–	$ 131	$ 131	(2)
Average pay rate						4.90%	4.90%	
Average receive rate						(a)	(a)	

(a) Rate is 3-month LIBOR, which was 2.56% at December 31, 2004

December 31, 2003 (dollars in millions)	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value December 31, 2003
Fixed rate long-term debt	$ 300	$ 300	–	$ 200	$ 300	$ 1,688	$ 2,788	$ 3,065
Average interest rate	6.9%	7.50%	–	6.80%	6.65%	6.09%	6.44%	
Variable rate long-term debt	–	–	–	–	–	$ 620	$ 620	$ 621
Average interest rate	–	–	–	–	–	–	1.09%	

Commodity Price Risk

PEC is exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related products marketed and purchased as a result of its ownership of energy-related assets. PEC's exposure to these fluctuations is significantly limited by cost-based regulation. Each state commission allows electric utilities to recover certain of these costs through various cost recovery clauses to the extent the respective commission determines that such costs are prudent. Therefore, while there may be a delay in the timing between when these costs are incurred and when these costs are recovered from the ratepayers, changes from year to year have no material impact on operating results. PEC may engage in limited economic hedging activity using natural gas and electricity financial instruments. Refer to Note 13 to the PEC Consolidated Financial Statements for additional information with regard to PEC's commodity contracts and use of derivative financial instruments.

PEC performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% increase or decrease in quoted market prices in the near term on its derivative commodity instruments would not have had a material effect on PEC's consolidated financial position, results of operations or cash flows as of December 31, 2004.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following consolidated financial statements, supplementary data and consolidated financial statement schedules are included herein:

All other schedules have been omitted as not applicable or not required or because the information required to be shown is included in the Consolidated Financial Statements or the Notes to the Consolidated Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF PROGRESS ENERGY, INC.

We have audited the accompanying consolidated balance sheets of Progress Energy, Inc., and its subsidiaries (the Company) at December 31, 2004 and 2003, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 1D and 18A to the consolidated financial statements, in 2003, the Company adopted Statement of Financial Accounting Standards No. 143 and Derivatives Implementation Group Issue C20.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 7, 2005, expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Raleigh, North Carolina
March 7, 2005

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of INCOME

(in millions except per share data) Years ended December 31	2004	2003	2002
Operating Revenues			
Electric	$ 7,153	$ 6,741	$ 6,601
Diversified business	2,619	2,000	1,490
Total Operating Revenues	9,772	8,741	8,091
Operating Expenses			
Utility			
Fuel used in electric generation	2,011	1,695	1,586
Purchased power	868	862	862
Operation and maintenance	1,475	1,421	1,390
Depreciation and amortization	878	883	820
Taxes other than on income	425	405	386
Diversified business			
Cost of sales	2,288	1,748	1,410
Depreciation and amortization	190	157	118
Impairment of long-lived assets	–	17	364
(Gain)/loss on the sale of assets	(57)	1	–
Other	218	195	145
Total Operating Expenses	8,296	7,384	7,081
Operating Income	1,476	1,357	1,010
Other Income (Expense)			
Interest income	14	11	15
Impairment of investments	–	(21)	(25)
Other, net	8	(16)	27
Total Other Income (Expense)	22	(26)	17
Interest Charges			
Net interest charges	653	635	641
Allowance for borrowed funds used during construction	(6)	(7)	(8)
Total Interest Charges, Net	647	628	633
Income from Continuing Operations before Income Tax, Minority Interest, and Cumulative Effect of Changes in Accounting Principles	851	703	394
Income Tax Expense (Benefit)	115	(111)	(158)
Income from Continuing Operations before Minority Interest and Cumulative Effect of Changes in Accounting Principles	736	814	552
Minority Interest, Net of Tax	(17)	3	–
Income from Continuing Operations Before Cumulative Effect of Change in Accounting Principles	753	811	552
Discontinued Operations, Net of Tax	6	(8)	(24)
Cumulative Effect of Changes in Accounting Principles, Net of Tax	–	(21)	–
Net Income	$ 759	$ 782	$ 528
Average Common Shares Outstanding	242	237	217
Basic Earnings per Common Share			
Income from Continuing Operations before Cumulative Effect of Changes in Accounting Principles	$ 3.11	$ 3.42	$ 2.54
Discontinued Operations, Net of Tax	.02	(.03)	(.11)
Cumulative Effect of Changes in Accounting Principles, Net of Tax	–	(.09)	–
Net Income	$ 3.13	$ 3.30	$ 2.43
Diluted Earnings per Common Share			
Income from Continuing Operations before Cumulative Effect of Changes in Accounting Principles	$ 3.10	$ 3.40	$ 2.53
Discontinued Operations, Net of Tax	.02	(.03)	(.11)
Cumulative Effect of Changes in Accounting Principles, Net of Tax	–	(.09)	–
Net Income	$ 3.12	$ 3.28	$ 2.42
Dividends Declared per Common Share	$ 2.32	$ 2.26	$ 2.20

See Notes to Consolidated Financial Statements.

PROGRESS ENERGY, INC.
CONSOLIDATED BALANCE SHEETS (continued)

(in millions) December 31	2004	2003
ASSETS		
Utility Plant		
Utility plant in service	$ 22,103	$ 21,680
Accumulated depreciation	(8,783)	(8,174)
Utility plant in service, net	13,320	13,506
Held for future use	13	13
Construction work in progress	799	559
Nuclear fuel, net of amortization	231	228
Total Utility Plant, Net	14,363	14,306
Current Assets		
Cash and cash equivalents	62	47
Short-term investments	82	226
Receivables	1,084	1,084
Inventory	982	907
Deferred fuel cost	229	270
Deferred income taxes	121	87
Prepayments and other current assets	175	268
Total Current Assets	2,735	2,889
Deferred Debits and Other Assets		
Regulatory assets	1,064	598
Nuclear decommissioning trust funds	1,044	938
Diversified business property, net	2,010	2,095
Miscellaneous other property and investments	446	464
Goodwill	3,719	3,726
Prepaid pension costs	42	462
Intangibles, net	337	357
Other assets and deferred debits	233	258
Total Deferred Debits and Other Assets	8,895	8,898
Total Assets	$ 25,993	$ 26,093

See Notes to Consolidated Financial Statements.

PROGRESS ENERGY, INC.
CONSOLIDATED BALANCE SHEETS (concluded)

(in millions) December 31	2004	2003
CAPITALIZATION AND LIABILITIES		
Common Stock Equity		
Common stock without par value, 500 million shares authorized, 247 and 246 million shares issued and outstanding, respectively	$ 5,360	$ 5,270
Unearned restricted shares (1 and 1 million shares, respectively)	(13)	(17)
Unearned ESOP shares (3 and 4 million shares, respectively)	(76)	(89)
Accumulated other comprehensive loss	(164)	(50)
Retained earnings	2,526	2,330
Total Common Stock Equity	7,633	7,444
Preferred Stock of Subsidiaries – Not Subject to Mandatory Redemption	93	93
Minority Interest	36	30
Long-Term Debt, Affiliate	270	270
Long-Term Debt, Net	9,251	9,664
Total Capitalization	17,283	17,501
Current Liabilities		
Current portion of long-term debt	349	868
Accounts payable	742	635
Interest accrued	219	228
Dividends declared	145	140
Short-term obligations	684	4
Customer deposits	180	167
Other current liabilities	742	608
Total Current Liabilities	3,061	2,650
Deferred Credits and Other Liabilities		
Noncurrent income tax liabilities	599	701
Accumulated deferred investment tax credits	176	190
Regulatory liabilities	2,654	2,879
Asset retirement obligations	1,282	1,271
Accrued pension and other benefits	562	508
Other liabilities and deferred credits	376	393
Total Deferred Credits and Other Liabilities	5,649	5,942
Commitments and Contingencies (Notes 22 and 23)		
Total Capitalization and Liabilities	$ 25,993	$ 26,093

See Notes to Consolidated Financial Statements.

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions) Years ended December 31	2004	2003	2002
Operating Activities			
Net income	$ 759	$ 782	$ 528
Adjustments to reconcile net income to net cash provided by operating activities			
(Income) loss from discontinued operations	(6)	8	24
Net (gain) loss on sale of operating assets	(57)	1	–
Impairment of long-lived assets and investments	–	38	389
Cumulative effect of changes in accounting principles	–	21	–
Depreciation and amortization	1,181	1,146	1,099
Deferred income taxes	(74)	(276)	(402)
Investment tax credit	(14)	(16)	(18)
Deferred fuel credit	(19)	(133)	(37)
Cash provided (used) by changes in operating assets and liabilities			
Receivables	(35)	(158)	(50)
Inventory	(108)	8	(66)
Prepayments and other current assets	(18)	39	(24)
Accounts payable	33	37	100
Other current liabilities	82	121	56
Regulatory assets and liabilities	(284)	(21)	46
Other	167	127	(18)
Net Cash Provided by Operating Activities	1,607	1,724	1,627
Investing Activities			
Gross utility property additions	(998)	(972)	(1,169)
Diversified business property additions	(236)	(584)	(558)
Nuclear fuel additions	(101)	(117)	(81)
Proceeds from sales of subsidiaries and other investments	366	579	43
Acquisition of businesses, net of cash	–	–	(365)
Purchases of short-term investments	(2,108)	(2,813)	(2,962)
Proceeds from sales of short-term investments	2,252	2,587	2,962
Acquisition of intangibles	(1)	(200)	(10)
Other	(46)	(26)	(61)
Net Cash Used in Investing Activities	(872)	(1,546)	(2,201)
Financing Activities			
Issuance of common stock, net	73	304	687
Issuance of long-term debt, net	421	1,539	1,783
Net increase (decrease) in short-term indebtedness	680	(696)	(247)
Retirement of long-term debt	(1,353)	(810)	(1,157)
Dividends paid on common stock	(558)	(541)	(480)
Other	17	12	(5)
Net Cash (Used in) Provided by Financing Activities	(720)	(192)	581
Net Increase (Decrease) in Cash and Cash Equivalents	15	(14)	7
Cash and Cash Equivalents at Beginning of Year	47	61	54
Cash and Cash Equivalents at End of Year	$ 62	$ 47	$ 61
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year – interest (net of amount capitalized)	$ 657	$ 643	$ 651
income taxes (net of refunds)	$ 189	$ 177	$ 219

Noncash Activities

- In April 2002, Progress Fuels Corporation, a subsidiary of the Company, acquired 100% of Westchester Gas Company. In conjunction with the purchase, the Company issued approximately $129 million in common stock (See Note 5D).
- In December 2003, Progress Telecommunications Corporation (PTC) and Caronet, Inc., both indirectly wholly owned subsidiaries of Progress Energy, and EPIK Communications, Inc., a wholly owned subsidiary of Odyssey Telecorp, Inc., contributed substantially all of their assets and transferred certain liabilities to Progress Telecom, LLC, a subsidiary of PTC (See Note 5A).

See Notes to Consolidated Financial Statements.

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of CHANGES in COMMON STOCK EQUITY

(in millions except per share data)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned Restricted Shares	Unearned ESOP Shares	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Stock Equity
Balance, January 1, 2002	219	$ 4,121	$ (14)	$ (114)	$ (32)	$ 2,043	$ 6,004
Net income						528	528
Other comprehensive loss					(206)		(206)
Issuance of shares	19	815					815
Purchase of restricted stock			(16)				(16)
Restricted stock expense recognition			8				8
Cancellation of restricted shares		(1)	1				–
Allocation of ESOP shares		16		12			28
Dividends ($2.20 per share)						(484)	(484)
Balance, December 31, 2002	238	4,951	(21)	(102)	(238)	2,087	6,677
Net income						782	782
Other comprehensive income					188		188
Issuance of shares	8	305					305
Stock options exercised		4					4
Purchase of restricted stock		(1)	(7)				(8)
Restricted stock expense recognition			10				10
Cancellation of restricted shares		(1)	1				–
Allocation of ESOP shares		12		13			25
Dividends ($2.26 per share)						(539)	(539)
Balance, December 31, 2003	246	5,270	(17)	(89)	(50)	2,330	7,444
Net income						759	759
Other comprehensive loss					(114)		(114)
Issuance of shares	1	62					62
Stock options exercised		18					18
Purchase of restricted stock			(7)				(7)
Restricted stock expense recognition			7				7
Cancellation of restricted shares		(4)	4				–
Allocation of ESOP shares		14		13			27
Dividends ($2.32 per share)						(563)	(563)
Balance, December 31, 2004	247	$ 5,360	$ (13)	$ (76)	$ (164)	$ 2,526	$ 7,633

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	2004	2003	2002
Net Income	$ 759	$ 782	$ 528
Other Comprehensive Income (Loss)			
Changes in net unrealized losses on cash flow hedges (net of tax benefit of $10, $7 and $18, respectively)	(18)	(12)	(28)
Reclassification adjustment for amounts included in net income (net of tax expense of ($16), ($11) and ($10), respectively)	26	19	16
Reclassification of minimum pension liability to regulatory assets (net of tax expense of ($2))	4	–	–
Minimum pension liability adjustment (net of tax benefit (expense) of $78, ($112) and $121, respectively)	(130)	177	(192)
Foreign currency translation and other	4	4	(2)
Other Comprehensive Income (Loss)	$ (114)	$ 188	$ (206)
Comprehensive Income	$ 645	$ 970	$ 322

See Notes to Consolidated Financial Statements.

PROGRESS ENERGY, INC. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

Progress Energy, Inc. (Progress Energy or the Company) is a holding company headquartered in Raleigh, North Carolina. The Company is registered under the Public Utility Holding Company Act of 1935 (PUHCA), as amended, and as such, the Company and its subsidiaries are subject to the regulatory provisions of PUHCA. Effective January 1, 2003, three of the Company's subsidiaries, Carolina Power & Light Company (CP&L), Florida Power Corporation and Progress Ventures, Inc., began doing business under the assumed names Progress Energy Carolinas, Inc. (PEC), Progress Energy Florida, Inc. (PEF) and Progress Energy Ventures, Inc. (PVI), respectively.

Through its wholly owned subsidiaries, PEC and PEF, the Company's PEC Electric and PEF segments are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. The Progress Ventures business unit consists of the Fuels business segment (Fuels) and Competitive Commercial Operations (CCO) operating segments. The Fuels segment is involved in natural gas drilling and production, coal terminal services, coal mining, synthetic fuel production, fuel transportation and delivery. The CCO segment includes nonregulated generation and energy marketing activities. Through the Rail Services (Rail) segment, the Company is involved in nonregulated railcar repair, rail parts reconditioning and sales and scrap metal recycling. Through its other business units, the Company engages in other nonregulated business areas, including telecommunications and energy management and related services. Progress Energy's legal structure is not currently aligned with the functional management and financial reporting of the Progress Ventures business unit. Whether, and when, the legal and functional structures will converge depends upon legislative and regulatory action, which cannot currently be anticipated.

B. Basis of Presentation

The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the activities of the Company and its majority-owned subsidiaries. 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," 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.

The consolidated financial statements of the Company and its subsidiaries include the majority-owned and controlled subsidiaries. Noncontrolling interests in the 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 the Company does not have control, but has the ability to exercise influence over operating and financial policies (generally 20%–50% 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). These equity method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, the Company has equity method investments of approximately $27 million and $36 million, respectively.

Certain investments in debt and equity securities that have readily determinable market values, and for which the Company does not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." These investments include investments held in trust funds, pursuant to United States Nuclear Regulatory Commission (NRC) requirements, to fund certain costs of decommissioning nuclear plants. The fair value of these trust funds was $1.044 billion and $938 million at December 31, 2004 and 2003, respectively. The Company also 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 the Company intends to sell these instruments generally within 30 days from the balance sheet date, they are classified as current assets. At December 31, 2004 and 2003, the fair value of these investments was $82 million and $226 million, respectively. Other investments in debt and equity securities are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, the fair value of these other investments was $39 million and $39 million, respectively.

Other investments are stated principally at cost. These cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004, and 2003, the Company has approximately $14 million and $14 million, respectively, of cost method investments.

The results of operations of Rail are reported one month in arrears. During 2003, the Company ceased recording portions of the Fuels' segment operations one month in arrears. The net impact of this action increased net income by $2 million for the year.

Certain amounts for 2003 and 2002 have been reclassified to conform to the 2004 presentation. Reclassifications include the reclassification of instruments used in PEC's cash management program from cash and cash equivalents to short-term investments of $226 million at December 31, 2003, in the Consolidated Balance Sheets. In the Consolidated Statements of Cash Flow for each of the three years in the period ended December 31, 2004, total cash balances and total cash flows used in investing activities were revised to reflect the reclassification of these instruments from cash and cash equivalents to short-term investments.

C. Consolidation of Variable Interest Entities

The Company consolidates all voting interest entities in which it owns a majority voting interest and all variable interest entities for which it is the primary beneficiary in accordance with FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51" (FIN No. 46R). The Company is the primary beneficiary of and consolidates two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Internal Revenue Code (Code). As of December 31, 2004, the total assets of the two entities were $37 million, the majority of which are collateral for the entities' obligations and are included in other current assets and miscellaneous other property and investments in the Consolidated Balance Sheets.

The Company is the primary beneficiary of a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. The Company has requested but has not received all the necessary information to determine the primary beneficiary of the limited partnership's underlying 17 partnership investments, and has applied the information scope exception in FIN No. 46R, paragraph 4(g) to the 17 partnerships. The Company has no direct exposure to loss from the 17 partnerships; the Company's only exposure to loss is from its investment of less than $1 million in the consolidated limited partnership. The Company will continue its efforts to obtain the necessary information to fully apply FIN No. 46R to the 17 partnerships. The Company 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 the Company's Consolidated Balance Sheets.

The Company has variable interests in two power plants resulting from long-term power purchase contracts. The Company has requested the necessary information to determine if the counterparties are variable interest entities or to identify the primary beneficiaries. Both entities declined to provide the Company with the necessary financial information, and the Company has applied the information scope exception in FIN No. 46R, paragraph 4(g). The Company's only significant exposure to variability from these contracts results from fluctuations in the market price of fuel used by the two entities' plants to produce the power purchased by the Company. The Company is able to recover these fuel costs under PEC's fuel clause. Total purchases from these counterparties were approximately $58 million, $53 million and $53 million in 2004, 2003 and 2002, respectively. The Company will continue its efforts to obtain the necessary information to fully apply FIN No. 46R to these contracts. The combined generation capacity of the two entities' power plants is approximately 880 MW. The Company believes that if it is determined to be the primary beneficiary of these two entities, the effect of consolidating the entities would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on the Company's common stock equity, net earnings or cash flows. However, because the Company has not received any financial information from these two counterparties, the impact cannot be determined at this time.

The Company also has interests in several other variable interest entities for which the Company is not the primary beneficiary. These arrangements include investments in approximately 28 limited partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. The aggregate maximum loss exposure at December 31, 2004, that the Company could be required to record in its income statement as a result of these arrangements totals approximately $38 million. The creditors of these variable interest entities do not have recourse to the general credit of the Company in excess of the aggregate maximum loss exposure.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

In preparing consolidated financial statements that conform with 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

The Company recognizes 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.

FUEL COST DEFERRALS

Fuel expense includes fuel costs or recoveries that are deferred through fuel clauses established by the electric 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

PEC and PEF collect from customers certain excise taxes levied by the state or local government upon the customers. PEC and PEF account for excise taxes on a gross basis. For the years ended December 31, 2004, 2003 and 2002, gross receipts tax, franchise taxes and other excise taxes of approximately $240 million, $217 million and $212 million, respectively, are included in utility revenues and taxes other than on income in the Consolidated Statements of Income.

STOCK-BASED COMPENSATION

The Company measures compensation expense for stock options as the difference between the market price of its common stock and the exercise price of the option at the grant date. The exercise price at which options are granted by the Company equals the market price at the grant date, and accordingly, no compensation expense has been recognized for stock option grants. For purposes of the pro forma disclosures required by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – An Amendment of FASB Statement No. 123" (SFAS No. 148), the estimated fair value of the Company's stock options is amortized to expense over the options' vesting period. The following table illustrates the effect on net income and earnings per share if the fair value method had been applied to all outstanding and unvested awards in each period:

(in millions except per share data)	2004	2003	2002
Net income, as reported	$ 759	$ 782	$ 528
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	10	11	8
Pro forma net income	$ 749	$ 771	$ 520
Earnings per share			
Basic – as reported	$ 3.13	$ 3.30	$ 2.43
Basic – pro forma	$ 3.09	$ 3.25	$ 2.40
Diluted – as reported	$ 3.12	$ 3.28	$ 2.42
Diluted – pro forma	$ 3.08	$ 3.24	$ 2.39

See Note 2 for a discussion of newly issued accounting guidance related to stock-based compensation.

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. The Company capitalizes 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 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, the Company adopted the guidance in SFAS No. 143 to account for legal obligations associated with the retirement of certain tangible long-lived assets. The present value of retirement costs for which the Company has 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.

The adoption of this statement had no impact on the income of the regulated entities, as the effects were offset by the establishment of a regulatory asset and a regulatory liability pursuant to SFAS No. 71 (See Note 8A). The North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (SCPSC) and the Florida Public Service Commission (FPSC) issued orders to authorize deferral of all prospective effects related to SFAS No. 143 as a regulatory asset or liability (See Note 8A). Therefore, SFAS No. 143 has no impact on the income of the regulated entities.

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 6A). 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 8).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method. In the Company's 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 Federal Energy Regulatory Commission (FERC).

CASH AND CASH EQUIVALENTS

The Company considers 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

The Company accounts for inventory using the average-cost method. Inventories are valued at the lower of average cost or market.

REGULATORY ASSETS AND LIABILITIES

The Company's regulated 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 Company records 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 8A).

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 6B. Depletion of mineral rights is provided on the units-of-production method based upon the estimates of recoverable amounts of clean mineral.

The Company uses the full-cost method to account for its 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 the Company's 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 life using the straight-line method consistent with ratemaking treatment (See Note 8A).

INCOME TAXES

The Company and its affiliates file a consolidated federal income tax return. 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 AMT 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.

DERIVATIVES

The Company accounts 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 and 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. The Company generally designates 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, the Company 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.

ENVIRONMENTAL

As discussed in Note 22, the Company accrues environmental remediation liabilities when the criteria for SFAS No. 5, "Accounting for Contingencies" (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 the Company's asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

As discussed in Note 10, the Company reviews 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. The accounting for impairment of assets is based on SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

The Company reviews its investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. The Company considers 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 the Company determines that an other-than-temporary decline exists in the value of its investments, it is the Company's 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, the Company is required to write-down capitalized costs to this level. The Company performs this ceiling test calculation every quarter. No write-downs were required in 2004, 2003 or 2002.

SUBSIDIARY STOCK TRANSACTIONS

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

2. NEW ACCOUNTING STANDARDS

FASB STAFF POSITION 106-2, "ACCOUNTING AND DISCLOSURE REQUIREMENTS RELATED TO THE MEDICARE PRESCRIPTION DRUG IMPROVEMENT AND MODERNIZATION ACT OF 2003"

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law. In accordance with guidance issued by the Financial Accounting Standards Board (FASB) in FASB Staff Position 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," (FASB Staff Position 106-1) the Company elected to defer accounting for the effects of the Medicare Act due to uncertainties regarding the effects of the implementation of the Medicare Act and the accounting for certain provisions of the Medicare Act. In May 2004, the FASB issued definitive accounting guidance for the Medicare Act in FASB Staff Position 106-2, which was effective for the Company in the third quarter of 2004. FASB Staff Position 106-2 results in the recognition of lower other postretirement employment benefit (OPEB) costs to reflect prescription drug-related federal subsidies to be received under the Medicare Act. As a result of the Medicare Act, the Company's accumulated postretirement benefit obligation as of January 1, 2004, was reduced by approximately $83 million, and the Company's 2004 net periodic cost was reduced by approximately $13 million.

SFAS NO. 123 (REVISED 2004), "SHARE-BASED PAYMENT" (SFAS NO. 123R)

In December 2004, the FASB issued SFAS No. 123R, which revises SFAS No. 123, "Accounting for Stock-Based Compensation," and supersedes Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." The key requirement of SFAS No. 123R is that the cost of share-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. Previously, entities could elect to continue accounting for such awards at their grant date intrinsic value under APB Opinion No. 25, and the Company made that election. The intrinsic value method resulted in the Company recording no compensation expense for stock options granted to employees (See Note 11).

SFAS No. 123R will be effective for the Company on July 1, 2005. The Company intends to implement the standard using the required modified prospective method. Under that method, the Company will record compensation expense under SFAS No. 123R for all awards it grants after July 1, 2005, and it will record compensation expense (as previous awards continue to vest) for the unvested portion of previously granted awards that remain outstanding at July 1, 2005. In 2004, the Company made the decision to cease granting stock options and intends to replace that compensation program with other programs. Therefore, the amount of stock option expense expected to be recorded in 2005 is below the amount that would have been recorded if the stock option program had continued. The Company expects to record approximately $3 million of pre-tax expense for stock options in 2005.

PROPOSED FASB INTERPRETATION OF SFAS NO. 109, "ACCOUNTING FOR INCOME TAXES"

In July 2004, the FASB stated that it plans to issue 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 FASB has indicated that the interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the consolidated financial statements. The exposure draft is expected to be issued in the first quarter of 2005. The Company cannot predict what actions the FASB will take or how any such actions might ultimately affect the Company's financial position or results of operations, but such changes could have a material impact on the Company's evaluation and recognition of Section 29 tax credits (See Note 23E).

3. HURRICANE RELATED COSTS

Hurricanes Charley, Frances, Ivan and Jeanne struck significant portions of the Company's service territories during the third quarter of 2004, significantly impacting PEF's territory. As of December 31, 2004, restoration of the Company's systems from hurricane-related damage was estimated at $398 million. PEC incurred restoration costs of $13 million, of which $12 million was charged to operation and maintenance expense and $1 million was charged to capital expenditures. PEF had estimated total costs of $385 million, of which $47 million was charged to capital expenditures, and $338 million was charged to the storm damage reserve pursuant to a regulatory order.

In accordance with a regulatory order, PEF accrues $6 million annually to a storm damage reserve and is allowed to defer losses in excess of the accumulated reserve for major storms. Under the order, the storm reserve is charged with operation and maintenance expenses related to storm restoration and with capital expenditures related to storm restoration that are in excess of expenditures assuming normal operating conditions. As of December 31, 2004, $291 million of hurricane restoration costs in excess of the previously recorded storm reserve of $47 million had been classified as a regulatory asset recognizing the probable recoverability of these costs. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail ratepayers over a two-year period. Storm reserve costs of $13 million were attributable to wholesale customers. The Company has received approval from the FERC to amortize these costs consistent with recovery of such amounts in wholesale rates. PEF continues to review the restoration cost invoices received. Given that not all invoices have been received as of December 31, 2004, PEF will update its petition with the FPSC upon receipt and audit of all actual charges incurred. Hearings on PEF's petition for recovery of $252 million of storm costs filed with the FPSC are scheduled to begin on March 30, 2005.

On November 17, 2004, the Citizens of the State of Florida, by and through Harold McLean, Public Counsel, and the Florida Industrial Power Users Group (FIPUG), (collectively, Joint Movants), filed a Motion to Dismiss PEF's petition to recover the $252 million in storm costs. On November 24, 2004, PEF responded in opposition to the motion, which was also the FPSC staff's position in its recommendation to the Commission on December 21, 2004, that it should deny the Motion to Dismiss. On January 4, 2005, the Commission ruled in favor of PEF and denied Joint Movant's Motion to Dismiss.

PEF's January 2005 notice to the FPSC of its intent to file for an increase in its base rates effective January 1, 2006, anticipates the need to replenish the depleted storm reserve balance and adjust the annual $6 million accrual in light of recent storm history to restore the reserve to an adequate level over a reasonable time period (See Note 8C).

PEC does not have an ongoing regulatory mechanism to recover storm costs; therefore, hurricane restoration costs recorded in the third quarter of 2004 were charged to operations and maintenance expenses or capital expenditures based on the nature of the work performed. In connection with other storms, PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over a five-year period. PEC did not seek deferral of 2004 storm costs from the NCUC (See Note 8B).

4. DIVESTITURES

A. Sale of Natural Gas Assets

In December 2004, the Company sold certain gas-producing properties and related assets owned by Winchester Production Company, Ltd. (Winchester Production), an indirectly wholly owned subsidiary of Progress Fuels Corporation (Progress Fuels), which is included in the Fuels 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 the Company's 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.

B. Divestiture of Synthetic Fuel Partnership Interests

In June 2004, the Company through its subsidiary, Progress Fuels, sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, 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 Company's book value of the interests sold totaled approximately $5 million. The Company received total gross proceeds of $10 million in 2004. Based on projected production and tax credit levels, the Company anticipates receiving approximately $24 million in 2005, approximately $31 million in 2006, approximately $32 million in 2007, and approximately $8 million through the second quarter of 2008. 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.

C. Railcar Ltd., Divestiture

In December 2002, the Progress Energy Board of Directors adopted a resolution approving the sale of Railcar Ltd., a subsidiary included in the Rail Services segment. An estimated pre-tax impairment of $59 million on assets held for sale was recognized in December 2002 to write-down the assets to fair value less costs to sell. This impairment has been included in impairment of long-lived assets in the Consolidated Statements of Income (See Note 10A). In March 2003, the Company signed a letter of intent to sell the majority of Railcar Ltd. assets to The Andersons, Inc., and the transaction closed in February 2004. Proceeds from the sale were approximately $82 million before transaction costs and taxes of approximately $13 million. In July 2004, the Company sold the remaining assets classified as held for sale to a third-party for net proceeds of $6 million. The assets of Railcar Ltd. were grouped as assets held for sale and were included in other current assets on the Consolidated Balance Sheets at December 31, 2003, at approximately $75 million, which reflected the Company's estimates of the fair value expected to be realized from the sale of these assets less costs to sell.

D. Mesa Hydrocarbons, Inc., Divestiture

In October 2003, the Company sold certain gas-producing properties owned by Mesa Hydrocarbons, LLC, a wholly owned subsidiary of Progress Fuels. Net proceeds were approximately $97 million. Because the Company utilizes the full-cost method of accounting for its oil and gas operations, the pre-tax gain of approximately $18 million was applied to reduce the basis of the Company's 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.

E. NCNG Divestiture

On September 30, 2003, the Company completed the sale of North Carolina Natural Gas Corporation (NCNG) and the Company's 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 and $16 million for the years ended December 31, 2003 and 2002, respectively, has been allocated to discontinued operations based on the net assets of NCNG, assuming a uniform debt-to-equity ratio across the Company's operations. The Company ceased recording depreciation effective October 1, 2002, upon classification of the assets as discontinued operations. After-tax depreciation expense recorded by NCNG for the year ended December 31, 2002, was $9 million. Results of discontinued operations for years ended December 31 were as follows:

(in millions)	2004	2003	2002
Revenues	$ –	$ 284	$ 300
Earnings before income taxes	$ –	$ 6	$ 9
Income tax expense	–	2	4
Net earnings from discontinued operations	–	4	5
Gain/(Loss) on disposal of discontinued operations, including applicable income tax benefit / (expense) of $6, $1 and $3, respectively	6	(12)	(29)
Earnings (loss) from discontinued operations	$ 6	$ (8)	$ (24)

During 2004, the Company 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.

5. ACQUISITIONS AND BUSINESS COMBINATIONS

A. Progress Telecommunications Corporation

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. 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 holds a 55% ownership interest in, and is the parent of, PT LLC. Odyssey holds a combined 45% ownership interest in PT LLC through EPIK and Caronet. The accounts of PT LLC have been included in the Company's 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 or 2002.

B. Acquisition of Natural Gas Reserves

During 2003, Progress Fuels entered into several independent transactions to acquire approximately 200 natural gas-producing wells with proven reserves of approximately 190 billion cubic feet (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 years ended December 31, 2003 and 2002.

C. Wholesale Energy Contract Acquisition

In May 2003, 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 calls for 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 9). The power supply agreement terminates in 2015, with a first refusal right to extend for five years. The agreement includes the use of 640 megawatts (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.

D. Westchester Acquisition

In April 2002, Progress Fuels, a subsidiary of Progress Energy, acquired 100% of Westchester Gas Company (Westchester). During 2004 the name of the company was changed to Winchester Energy Co. Ltd.. The acquisition included approximately 215 natural gas-producing wells, 52 miles of intrastate gas pipeline and 170 miles of gas-gathering systems located within a 25-mile radius of Jonesville, Texas, on the Texas-Louisiana border.

The aggregate purchase price of approximately $153 million consisted of cash consideration of approximately $22 million and the issuance of 2.5 million shares of Progress Energy common stock then valued at approximately $129 million. The purchase price included approximately $2 million of direct transaction costs. The final purchase price was allocated to oil and gas properties, intangible assets, diversified business property, net working capital and deferred tax liabilities for approximately $152 million, $9 million, $32 million, $5 million and $45 million, respectively. The $9 million intangible assets relates to customer contracts (See Note 9).

The acquisition has been accounted for using the purchase method of accounting and, accordingly, the results of operations for Westchester have been included in Progress Energy's Consolidated Financial Statements since the date of acquisition. 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, 2002.

E. Generation Acquisition

In February 2002, PVI acquired 100% of two electric generating projects located in Georgia from LG&E Energy Corp., a subsidiary of Powergen plc. The two projects consist of 1) Walton County Power, LLC, in Monroe, Georgia, a 460 MW natural gas-fired plant placed in service in June 2001 and 2) Washington County Power, LLC, in Washington County, Georgia, a 600 MW natural gas-fired plant placed in service in June 2003. The Walton and Washington projects have been accounted for using the purchase method of accounting and, accordingly, have been included in the Consolidated Financial Statements since the acquisition date.

In the final allocation, the aggregate cash purchase price of approximately $348 million was allocated to diversified business property, intangibles and goodwill for $228 million, $56 million and $64 million, respectively (See Note 9). Of the acquired intangible assets, $33 million was assigned to tolling and power sale agreements with LG&E Energy Marketing, Inc., for each project and $23 million was assigned to interconnection contracts. Goodwill was assigned to the CCO segment and will be deductible for tax purposes.

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, 2002.

6. 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 for each:

(in millions)	2004	2003
Production plant (7-33 years)	**$ 11,966**	$ 12,044
Transmission plant (30-75 years)	**2,282**	2,167
Distribution plant (12-50 years)	**6,749**	6,432
General plant and other (8-75 years)	**1,106**	1,037
Utility plant in service	**$ 22,103**	$ 21,680

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.

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 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 7.2% in 2004, 4.0% in 2003 and 6.2% in 2002, respectively. The composite AFUDC rate for PEF's electric utility plant was 7.8% in 2004, 2003 and 2002.

Depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.2%, 2.5% and 2.6% in 2004, 2003 and 2002, respectively. The depreciation provisions related to utility plant were $463 million, $517 million and $488 million in 2004, 2003 and 2002, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, asset retirement obligation (ARO) accretion, cost of removal provisions (See Note 6D), regulatory approved expenses (See Note 8 and Note 22) and NC Clean Air Legislation amortization (See Note 8B).

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 new depreciation rates were effective January 1, 2004.

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, 2004, 2003 and 2002 were $140 million, $143 million and $141 million, respectively, and are included in fuel used for electric generation in the Consolidated Statements of Income.

B. Diversified Business Property

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

(in millions)	2004	2003
Equipment (3-25 years)	$ 383	$ 246
Nonregulated generation plant and equipment (3-40 years)	1,302	1,299
Land and mineral rights	107	93
Buildings and plants (5-40 years)	131	125
Oil and gas properties (units-of-production)	336	412
Telecommunications equipment (5-20 years)	80	63
Rail equipment (3-20 years)	29	125
Marine equipment (3-35 years)	87	83
Computers, office equipment and software (3-10 years)	36	36
Construction work in progress	26	13
Accumulated depreciation	(507)	(400)
Diversified business property, net	$ 2,010	$ 2,095

The synthetic fuel facilities are being depreciated through 2007 when the Section 29 tax credits will expire. The Company's nonregulated businesses capitalize interest costs under SFAS No. 34, "Capitalization of Interest Costs." During the years ended December 31, 2004, 2003 and 2002, respectively, the Company capitalized $7 million, $20 million and $38 million, respectively, of its interest cost of $660 million, $655 million and $679 million. Capitalized interest for 2004 is related to the expansion of Fuels' gas operations. Capitalized interest in 2003 and 2002 is related to the expansion of its nonregulated generation portfolio at PVI. Capitalized interest is included in diversified business property, net on the Consolidated Balance Sheets. Diversified business depreciation expense was $148 million, $120 million and $85 million for December 31, 2004, 2003 and 2002, respectively.

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. 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 ($ in millions):

2004 Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	**Mayo Plant**	**83.83%**	**$ 516**	**$ 249**	**$ 1**
PEC	**Harris Plant**	**83.83%**	**3,185**	**1,387**	**13**
PEC	**Brunswick Plant**	**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**

2003 Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo Plant	83.83%	$ 464	$ 242	$ 50
PEC	Harris Plant	83.83%	3,248	1,424	7
PEC	Brunswick Plant	81.67%	1,611	885	21
PEC	Roxboro Unit 4	87.06%	323	139	1
PEF	Crystal River Unit 3	91.78%	875	442	46
PEF	Intercession City Unit P11	66.67%	22	6	6

In the tables above, plant investment and accumulated depreciation are not reduced by the regulatory disallowances related to the Shearon Harris Nuclear Plant (Harris Plant).

D. Asset Retirement Obligations

At December 31, 2004 and 2003, the asset retirement costs related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $277 million and $354 million, respectively. Funds set aside in the Company's nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $1.044 billion and $938 million at December 31, 2004 and 2003, respectively. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 8A).

Decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million in each of 2004, 2003 and 2002. 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. The Company's expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 asset removal obligations, which are included in depreciation and amortization expense, were $160 million, $158 million and $149 million in 2004, 2003 and 2002, respectively.

The utilities recognize removal, nonirradiated decommissioning and dismantlement costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 8A). At December 31, 2004, such costs consist of removal costs of $1.606 billion, removal costs for nonirradiated areas at nuclear facilities of $131 million and amounts previously collected for dismantlement of fossil generation plants of $144 million. At December 31, 2003, such costs consist of removal costs of $1.846 billion, removal costs for nonirradiated areas at nuclear facilities of $129 million and amounts previously collected for dismantlement of fossil generation plants of $143 million. During 2004, PEC reduced its estimated removal costs to take into account the estimates used in the depreciation studies implemented during 2004 (See Note 6A). This resulted in a downward revision in the PEC estimated removal costs and equal increase in accumulated depreciation of approximately $345 million.

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 estimates, in 2004 dollars, are $294 million for Robinson Unit No. 2, $290 million for Brunswick Unit No. 1, $313 million for Brunswick Unit No. 2 and $359 million for the Harris Plant. 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 the Brunswick and Harris nuclear generating facilities. NRC operating licenses held by PEC currently expire in December 2014 and September 2016 for Brunswick Units 2 and 1, respectively. An application to extend these licenses 20 years was submitted in October 2004. The NRC operating license held by PEC for the Shearon Harris Nuclear Plant (Harris Plant) 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 has renewed the operating license for PEC's Robinson Nuclear Plant (Robinson) for an additional 20 years through July 2030.

PEF's most recent site-specific estimate of decommissioning costs for the Crystal River Nuclear Plant (CR3) was developed in 2000 based on prompt dismantlement decommissioning. The estimate, in 2000 dollars, is $491 million and is subject to change based on the same factors as discussed above for PEC's estimates. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for Crystal River Unit No. 3 (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.

The Company has identified but not recognized AROs related to electric transmission and distribution and telecommunications assets as the result of easements over property not owned by the Company. 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 the Company intends to utilize these properties indefinitely. In the event the Company decides to abandon or cease the use of a particular easement, an ARO would be recorded at that time.

The Company's nonregulated AROs relate to coal mine operations, synthetic fuel operations and gas production of Progress Fuels. The related asset retirement costs, net of accumulated depreciation, totaled $10 million and $5 million at December 31, 2004 and 2003, respectively.

The following table shows the changes to the asset retirement obligations. Additions relate primarily to additional reclamation obligations at coal mine operations of Progress Fuels. The deductions to regulated ARO related to PEC re-measuring 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.

(in millions)	Regulated	Nonregulated
Asset retirement obligations as of January 1, 2003	$ 1,183	$ 10
Additions	–	11
Accretion expense	68	1
Deductions	–	(2)
Asset retirement obligations as of December 31, 2003	1,251	20
Additions	–	6
Accretion expense	73	2
Deductions	(63)	(7)
Asset retirement obligations as of December 31, 2004	$ 1,261	$ 21

The cumulative effect of initial adoption of this statement 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. Pro forma net income has not been presented for prior years because the pro forma application of SFAS No. 143 to prior years would result in pro forma net income not materially different from the actual amounts reported.

E. Insurance

PEC and PEF 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 $2.0 billion on the Brunswick and Harris Plants, and $1.1 billion on the Robinson and Crystal River Unit No. 3 (CR3) Plants.

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 million per week at the Brunswick and Harris Plants, $2.5 million per week at the Robinson Plant and $4.5 million per week at the CR3 Plant. An additional 110 weeks (71 weeks for CR3) of coverage is provided at 80% of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $29.3 million with respect to the primary coverage, $32.4 million with respect to the decontamination, decommissioning and excess property coverage, and $20.2 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 United States Nuclear Regulatory Commission (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 PEC and PEF are insured against public liability for a nuclear incident up to $10.8 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 $101 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 $10 million per reactor owned. Congress could possibly approve revisions to the Price Anderson Act during 2005 that could include increased limits and assessments per reactor owned. The final outcome of this matter cannot be predicted at this time.

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 the terrorist acts.

PEC and PEF 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 Notes 3 and 8A).

7. CURRENT ASSETS

RECEIVABLES

At December 31, receivables were comprised of:

(in millions)	2004	2003
Trade accounts receivable	$ 689	$ 705
Unbilled accounts receivable	271	293
Notes receivable	98	61
Other receivables	27	47
Unbilled other receivables	28	10
Allowance for doubtful accounts receivable	(29)	(32)
Total receivables	$ 1,084	$ 1,084

Income tax receivables and interest income receivables are not included in this classification. These amounts are in prepaids and other current assets on the Consolidated Balance Sheet.

INVENTORY

At December 31, inventory was comprised of:

(in millions)	2004	2003
Fuel for production	$ 235	$ 210
Inventory for sale	230	167
Materials and supplies	517	530
Total inventory	$ 982	$ 907

8. 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 applied to a separable portion of the Company's 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:

(in millions)	2004	2003
Deferred fuel cost – current (Note 8B and 8C)	$ 229	$ 270
Deferred fuel cost – long-term (Note 8B and 8C)	107	47
Deferred impact of ARO – PEC (Note 1D)	305	291
Income taxes recoverable through future rates (Note 15)	84	75
Loss on reacquired debt (Note 1D)	53	55
Deferred DOE enrichment facilities-related costs	16	24
Storm deferral (Notes 3 and 8B)	316	21
Postretirement benefits (Note 17)	74	9
Other	109	76
Total long-term regulatory assets	1,064	598
Deferred energy conservation cost – current	(8)	(7)
Non-ARO cost of removal (Note 6D)	(1,881)	(2,118)
Deferred impact of ARO (Note 1D)	(221)	(212)
Net nuclear decommissioning trust unrealized gains (Note 6D)	(224)	(204)
Postretirement benefits (Note 17B)	(45)	(211)
Storm reserve (Note 3)	–	(41)
Clean air compliance (Note 8B)	(248)	(74)
Other	(35)	(19)
Total long-term regulatory liabilities	(2,654)	(2,879)
Net regulatory assets (liabilities)	$ (1,369)	$ (2,018)

Except for portions of deferred fuel costs and deferred storm 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. The Company expects to fully recover these assets and refund the liabilities through customer rates under current regulatory practice.

B. PEC Retail Rate Matters

As of December 31, 2004, PEC's North Carolina retail fuel costs were underrecovered by $145 million. This amount is comprised of $117 million eligible for recovery in 2005 and $28 million deferred from a 2001 order from the NCUC that cannot be collected during 2005, and has therefore been classified as a long-term asset. PEC intends to collect this amount by October 31, 2007.

On October 15, 2004, the SCPSC approved PEC's request to leave fuel rates unchanged. The deferred fuel balance at December 31, 2004, is $23 million. This amount is eligible for recovery in PEC's 2005 South Carolina fuel review.

PEC obtained SCPSC and NCUC approval of fuel factors in annual fuel-adjustment proceedings. The NCUC approved an annual increase of $62 million, $20 million and $46 million by orders issued in September 2004, 2003 and 2002, respectively. The SCPSC approved PEC's petition each year and the changes were insignificant.

PEC filed with the SCPSC seeking permission to defer expenses incurred from the first quarter 2004 winter storm. 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.

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 ice storm and amortize them over a period of five years. PEC charged approximately $24 million in 2003 from Hurricane Isabel and from ice storms to the deferred account. PEC recognized $5 million and $3 million of NC storm amortization during 2004 and 2003, respectively.

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 2004 and 2003 and additional depreciation expense of approximately $53 million in 2002. Total accelerated depreciation recorded through December 31, 2004, was $403 million.

The North Carolina Clean Smokestacks Act enacted in June 2002 (NC Clean Air), requires state utilities to reduce emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from coal-fired plants. The NCUC has allowed the utilities to amortize and recover the costs 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 when setting the amortization amount for each year. PEC recognized $174 million and $74 million of clean air amortization during 2004 and 2003, respectively. This legislation freezes PEC's base rates in North Carolina for five years, subject to certain conditions (See Note 22).

In conjunction with the FPC merger, PEC reached a settlement with the Public Staff of the NCUC in which it agreed to provide credits to its nonreal time pricing customers in the amounts of $3 million in 2002, $5 million in 2003 and $6 million in both 2004 and 2005.

In conjunction with the acquisition of NCNG in 1999, PEC agreed not to seek a base retail electric rate increase in North Carolina and South Carolina through December 2004. The agreement not to seek a base retail electric rate increase in South Carolina was extended to December 2005 in conjunction with regulatory approval to form a holding company.

C. PEF Retail Rate Matters

On November 9, 2004, the FPSC approved PEF's underrecovered fuel costs of $156 million for 2004, of which PEF plans to defer $79 million until 2006 to mitigate the impact on customers resulting from the need to also recover hurricane-related costs. Therefore, $79 million of deferred fuel costs has been classified as a long-term asset. As of December 31, 2004, PEF was underrecovered in fuel costs by $168 million. The additional $12 million over and above the $156 million approved by the FPSC will be included in PEF's 2005 fuel filing.

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 the Company's affiliated coal supplier, Progress Fuels Corporation. 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 underruns. Any costs that exceed this estimate will not be recoverable absent extraordinary circumstances as found by the FPSC in subsequent proceedings.

See Note 3 for information on PEF's petition for storm cost recovery.

PEF RATE CASE SETTLEMENT

The FPSC initiated a rate proceeding in 2001 regarding PEF's future base rates. In March 2002, the parties in PEF's rate case entered into a Stipulation and Settlement Agreement (the Agreement) related to retail rate matters. The Agreement was approved by the FPSC in April 2002. The Agreement is generally effective from May 2002 through December 2005, provided, however, that if PEF's base rate earnings fall below a 10% return on equity, PEF may petition the FPSC to amend its base rates.

The Agreement provides that PEF will reduce its retail revenues from the sale of electricity by an annual amount of $125 million. The Agreement also provides that PEF will operate under a Revenue Sharing Incentive Plan (the Plan) through 2005, and thereafter until terminated by the FPSC, that establishes annual revenue caps and sharing thresholds. The Plan provides that retail base rate revenues between the sharing thresholds and the retail base rate revenue caps will be divided into two shares – a 1/3 share to be received by PEF's shareholders, and a 2/3 share to be refunded to PEF's retail customers, provided, however, that for the year 2002 only, the refund to customers was limited to 67.1% of the 2/3 customer share. The retail base rate revenue sharing threshold amounts for 2004, 2003 and 2002 were $1.370 billion, $1.333 billion and $1.296 billion, respectively, and will increase $37 million in 2005. The Plan also provides that all retail base rate revenues above the retail base rate revenue caps established for each year will be refunded to retail customers on an annual basis. For 2002, the refund to customers was limited to 67.1% of the retail base rate revenues that exceeded the 2002 cap. The retail base revenue caps for 2004, 2003 and 2002 were $1.430 billion, $1.393 billion and $1.356 billion, respectively, and will increase $37 million in 2005. Any amounts above the retail base revenue caps will be refunded 100% to customers. At December 31, 2004, $9 million has been accrued and will be refunded to retail customers by March 2005. The 2003 revenue sharing amount was $18 million, and was refunded to customers by April 30, 2004. Approximately $5 million was originally returned in March 2003 related to 2002 revenue sharing. However, in February 2003, the parties to the Agreement filed a motion seeking an order from the FPSC to enforce the Agreement. In this motion, the parties disputed PEF's calculation of retail revenue subject to refund and contended that the refund should be approximately $23 million. In July 2003, the FPSC ruled that PEF must provide an additional $18 million to its retail customers related to the 2002 revenue sharing calculation. PEF recorded this refund in the second quarter of 2003 as a charge against electric operating revenue and refunded this amount by October 2003.

The Agreement also provides that beginning with the in-service date of PEF's Hines Unit 2 and continuing through December 2005, PEF will be allowed to recover through the fuel cost recovery clause a return on average investment and depreciation expense for Hines Unit 2, to the extent such costs do not exceed the Unit's cumulative fuel savings over the recovery period. Hines Unit 2 is a 516 MW combined-cycle unit that was placed in service in December 2003. In 2004, PEF recovered $36 million through this clause related to Hines Unit 2.

In addition, PEF suspended retail accruals on its reserves for nuclear decommissioning and fossil dismantlement through December 2005. Additionally, for each calendar year during the term of the Agreement, PEF will record a $63 million depreciation expense reduction and may, at its option, record up to an equal annual amount as an offsetting accelerated depreciation expense. No accelerated depreciation expense was recorded during 2004 and 2003. In addition, PEF is authorized, at its discretion, to accelerate the amortization of certain regulatory assets over the term of the Agreement.

Under the terms of the Agreement, PEF agreed to continue the implementation of its four-year Commitment to Excellence Reliability Plan and expected to achieve a 20% improvement in its annual System Average Interruption Duration Index by no later than 2004. If this improvement level was not achieved for calendar years 2004 or 2005, PEF would have provided a refund of $3 million for each year the level is not achieved to 10% of its total retail customers served by its worst performing distribution feeder lines. PEF achieved this improvement level in 2004.

In January 2005, in anticipation of the expiration of its Stipulation and Settlement approved by the FPSC in 2002 to conclude PEF's then-pending rate case, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2006. In its notice, PEF requested the FPSC to approve calendar year 2006 as the projected test period for setting new base rates. The request for increased base rates is based on the fact that PEF has faced significant cost increases over the past decade and expects its operational costs to continue to increase. These costs include the costs associated with completion of the Hines 3 generation facility, extraordinary hurricane damage costs including capital costs which are not expected to be directly recoverable, the need to replenish the depleted storm reserve and the expected infrastructure investment necessary to meet high customer expectations, coupled with the demands placed on PEF as a result of strong customer growth. February 7, 2005, the FPSC acknowledged receipt of PEF's notice and authorized minimum filing requirements and testimony to be filed May 1, 2005.

D. Regional Transmission Organizations and Standard Market Design

In 2000, the Federal Energy Regulatory Commission (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 July 2002, the FERC issued its Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR). If adopted as proposed, the rules set forth in the SMD NOPR would have materially altered the manner in which transmission and generation services are provided and paid for. In April 2003, the FERC released a White Paper on the Wholesale Market Platform. The White Paper provided an overview of what the FERC intended to include in a final rule in the SMD NOPR docket. The White Paper retained the fundamental and most protested aspects of SMD NOPR, including mandatory RTOs and the FERC's assertion of jurisdiction over certain aspects of retail service. The FERC has not yet issued a final rule on SMD NOPR. The Company cannot predict the outcome of these matters or the effect that they may have on the GridSouth and GridFlorida proceedings currently ongoing before the FERC. By order issued December 22, 2004, the FERC terminated a portion of the proceedings regarding GridSouth. The GridSouth Companies asked the FERC for further clarification as to the portions of the GridSouth docket it intended to address. On March 2, 2005, the FERC affirmed that it only intended to close the mediation portion of the GridSouth docket. It is unknown what impact the future proceedings will have on the Company's earnings, revenues or prices.

The Florida Public Service Commission (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 currently scheduled to be presented at a FPSC workshop on May 25, 2005, with subsequent action by the FPSC to be thereafter determined.

The Company has $33 million and $4 million invested in GridSouth and GridFlorida, respectively, related to startup costs at December 31, 2004. The Company expects to recover these startup costs in conjunction with the GridSouth and GridFlorida original structures or in conjunction with any alternate combined transmission structures that emerge.

E. FERC Market Power Mitigation

A FERC order issued in November 2001 on certain unaffiliated utilities' triennial market-based wholesale power rate authorization updates required certain mitigation actions that those utilities would need to take for sales/purchases within their control areas and required those utilities to post information on their Web sites regarding their power systems' status. As a result of a request for rehearing filed by certain market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. 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 believes it would experience in passing one of the interim screens, on August 12, 2004, PEC notified the FERC that it would revise its Market-based Rate tariff to restrict it to sales outside PEC's control area and file a new cost-based tariff for sales within PEC's control area that incorporates the FERC's default cost-based rate methodologies for sales of one year or less. PEC anticipates making this filing in the first quarter of 2005. PEC does not anticipate that the current operations will be materially impacted by this change. Although the Company cannot predict the ultimate outcome of these changes, the Company does not anticipate that the current operations of PEC or PEF would be impacted materially if they were unable to sell power at market-based rates in their respective control areas.

F. Energy Delivery Capitalization Practice

The Company has reviewed its capitalization policies for its Energy Delivery business units in PEC and PEF. 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. The Company has implemented such changes effective January 1, 2005, which include more detailed classification of outage and emergency work and result in more precise estimation and a process of retesting 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 Company estimates that the combined impact for both utilities in 2005 will be that approximately $55 million of costs that would have been capitalized under the previous policies will be expensed. Pursuant to SFAS No. 71, PEC and PEF have informed the state regulators having jurisdiction over them of this change and that the new estimation process will be implemented effective January 1, 2005. The Company has also requested a method change from the IRS.

9. GOODWILL AND OTHER INTANGIBLE ASSETS

The Company performed the annual goodwill impairment test in accordance with FASB Statement No. 142, Goodwill and Other Intangible Assets, for the CCO segment in the first quarter of 2004, and the annual goodwill impairment test for the PEC Electric and PEF segments in the second quarter of 2004, each of which indicated no impairment.

The changes in the carrying amount of goodwill, by reportable segment, are as follows:

(in millions)	PEC Electric	PEF	CCO	Corporate and Other	Total
Balance as of January 1, 2003	$ 1,922	$ 1,733	$ 64	$ –	$ 3,719
Acquisitions	–	–	–	7	7
Balance as of December 31, 2003	**$ 1,922**	**$ 1,733**	**$ 64**	**$ 7**	**$ 3,726**
Purchase accounting adjustment	–	–	–	(7)	(7)
Balance as of December 31, 2004	**$ 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 Progress Telecommunications Corporation partial acquisition of EPIK and was reported in the Other segment. As discussed in Note 5A, the Company 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 Company's intangible assets at December 31 are as follows:

	2004		2003	
(in millions)	**Gross Carrying Amount**	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
Synthetic fuel intangibles	**$ 134**	**$ (80)**	$ 140	$ (64)
Power agreements acquired	**221**	**(39)**	221	(20)
Other	**119**	**(18)**	93	(13)
Total	**$ 474**	**$(137)**	$ 454	$ (97)

In June 2004, the Company sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, one of its synthetic fuel operations. Approximately $6 million in synthetic fuel intangibles and $3 million in related accumulated amortization were included in the basis of the partnership interest sold.

All of the Company's intangibles 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 of the Internal Revenue Code (Section 29) in December 2007 (See Note 23E). The intangibles related to power agreements acquired are being amortized based on the economic benefits of the contracts (See Notes 5C and 5D). Other intangibles are primarily acquired customer contracts and permits that are amortized over their respective lives. Of the increase in other intangible assets, $24 million resulted from the minimum pension liability adjustment at December 31, 2004 (See Note 17).

Amortization expense recorded on intangible assets for the years ended December 31, 2004, 2003 and 2002 was, in millions, $42, $37 and $33, respectively. The estimated annual amortization expense for intangible assets for 2005 through 2009, in millions, is approximately $35, $36, $36, $18 and $18, respectively.

10. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

The Company applies SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. In 2003 and 2002, the Company recorded pre-tax long-lived asset and investment impairments and other charges of approximately $38 million and $414 million, respectively.

A. Long-Lived Assets

Due to the reduction in coal production, the Company 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, the Company recorded asset impairments of $17 million on a pre-tax basis during the fourth quarter of 2003.

An estimated impairment of assets held for sale of $59 million is included in the 2002 amount, which relates to Railcar Ltd. (See Note 4C).

Due to the decline of the telecommunications industry and continued operating losses, the Company initiated an independent valuation study during 2002 to assess the recoverability of the long-lived assets of PTC and Caronet. Based on this assessment, the Company recorded asset impairments of $305 million on a pre-tax basis and other charges of $25 million on a pre-tax basis primarily related to inventory adjustments in the third quarter of 2002. This write-down constitutes a significant reduction in the book value of these long-lived assets.

The long-lived asset impairments include an impairment of property, plant and equipment, construction work in process and intangible assets. The impairment charge represents the difference between the fair value and carrying amount of these long-lived assets. The fair value of these assets was determined using a valuation study heavily weighted on the discounted cash flow methodology, using market approaches as supporting information.

B. Investments

The Company continually reviews its investments to determine whether a decline in fair value below the cost basis is other than temporary. In 2003, PEC's affordable housing investment (AHI) portfolio was reviewed and deemed to be impaired based on various factors including continued operating losses of the AHI portfolio and management performance issues arising at certain properties within the AHI portfolio. As a result, PEC recorded an impairment of $18 million on a pre-tax basis during the fourth quarter of 2003. PEC also recorded an impairment of $3 million for a cost investment.

In May 2002, Interpath Communication, Inc., merged with a third party. As a result, the Company reviewed the Interpath investment for impairment and wrote off the remaining amount of its cost-basis investment in Interpath, recording a pre-tax impairment of $25 million in the third quarter of 2002. In the fourth quarter of 2002, the Company sold its remaining interest in Interpath for a nominal amount.

11. EQUITY

A. Common Stock

At December 31, 2004, the Company had approximately 63 million shares of common stock authorized by the Board of Directors that remained unissued and reserved, primarily to satisfy the requirements of the Company's stock plans. In 2002, the Board of Directors authorized meeting the requirements of the Progress Energy 401(k) Savings and Stock Ownership Plan and the Investor Plus Stock Purchase Plan with original issue shares. During 2004, 2003 and 2002, respectively, the Company issued approximately 1 million, 8 million and 2 million shares under these plans for net proceeds of approximately $62 million, $305 million and $86 million. The Company continues to meet the requirements of the restricted stock plan with issued and outstanding shares.

In November 2002, the Company issued 14.7 million shares of common stock for net cash proceeds of approximately $600 million, which were primarily used to retire commercial paper. In April 2002, the Company issued 2.5 million shares of common stock, valued at approximately $129 million, in conjunction with the purchase of Westchester (See Note 5D).

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2004, there were no significant restrictions on the use of retained earnings.

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

The Company sponsors the Progress Energy 401(k) Savings and Stock Ownership Plan (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 within the Company as of January 1, 2003, were PEC, PEF, PTC, Progress Fuels (Corporate) and Progress Energy Service Company. Effective December 19, 2003, (the PT LLC/EPIK merger date), PTC no longer participates in the 401(k) plan. The 401(k), which has Company matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Company 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 Company 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 Company 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 then allocated to participants, are fully deductible for income tax purposes.

There were 3.5 million and 4.0 million ESOP suspense shares at December 31, 2004 and 2003, respectively, with a fair value of $156 million and $183 million, respectively. ESOP shares allocated to plan participants totaled 12.6 million and 13.1 million in December 31, 2004 and 2003, respectively. The Company's 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 Company common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. The Company currently meets 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 $21 million, $20 million and $20 million for the years ended December 31, 2004, 2003 and 2002, respectively. Total matching and incentive cost totaled approximately $32 million, $35 million and $30 million for the years ended December 31, 2004, 2003 and 2002, respectively. The Company has a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from the Company 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.

STOCK OPTION AGREEMENTS

Pursuant to the Company's 1997 Equity Incentive Plan and 2002 Equity Incentive Plan, amended and restated as of July 10, 2002, the Company may grant options to purchase shares of 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% vesting at the end of year three, while options granted to directors vest 100% 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 the Company's common stock on the grant date. The Company measures compensation expense for stock options as the difference between the market price of its common stock and the exercise price of the option at the grant date. The exercise price at which options are granted by the Company equals the market price at grant date and accordingly, no compensation expense has been recognized for any options granted during 2004, 2003 and 2002. The Company will begin expensing stock options on July 1, 2005, based on SFAS No. 123R (See Note 2). In 2004, however, the Company made the decision to cease granting stock options and intends to replace that compensation program with other programs. Therefore, the amount of stock option expense expected to be recorded in 2005 is below the amount that would have been recorded if the stock option program had continued.

The pro forma information presented in Note 1 regarding net income and earnings per share is required by SFAS No. 148. Under this statement, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The pro forma amounts presented in Note 1 have been determined as if the Company had accounted for its employee stock options under SFAS No. 123. 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	2002
Risk-free interest rate	**4.22%**	4.25%	4.14%
Dividend yield	**5.19%**	4.75%	5.20%
Volatility factor	**20.30%**	22.28%	24.98%
Weighted-average expected life of the options (in years)	**10**	10	10

The option valuation model requires the input of highly subjective assumptions, primarily stock price volatility, changes in which can materially affect the fair value estimate.

The options outstanding at December 31, 2004, 2003 and 2002 had a weighted-average remaining contractual life of 7.6, 8.7 and 9.3 years, respectively, and had exercise prices that ranged from $40.41 to $51.85. The tabular information for the option activity is as follows:

	2004		2003		2002	
(option quantities in millions)	**Number of Options**	**Weighted-Average Exercise Price**	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	**8.0**	**$ 43.54**	5.2	$ 42.84	2.3	$ 43.49
Granted	**–**	**–**	3.0	$ 44.70	2.9	$ 42.34
Forfeited	**(0.1)**	**$ 43.76**	(0.1)	$ 43.64	–	$ 43.71
Canceled	**(0.1)**	**$ 43.67**	(0.1)	$ 43.62	–	–
Exercised	**(0.4)**	**$ 42.82**	–	$ 43.00	–	–
Options outstanding, December 31	**7.4**	**$ 43.57**	8.0	$ 43.54	5.2	$ 42.84
Options exercisable, December 31 with a remaining contractual life of 7.6 years	**4.6**	**$ 43.35**	2.4	$ 43.09	0.8	$ 43.49
Weighted-average grant date fair value of options granted during the year		**–**		$ 7.16		$ 6.83

OTHER STOCK-BASED COMPENSATION PLANS

The Company has additional compensation plans for officers and key employees of the Company 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 program (RSA), both of which were established pursuant to the Company's 1997 Equity Incentive Plan and were continued under the Company's 2002 Equity Incentive Plan, as amended and restated as of July 10, 2002.

Under the terms of the PSSP, officers and key employees of the Company are granted 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 the Company's 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 the Company's results as compared to a peer group of utilities. Compensation expense is recognized over the vesting period based on the expected ultimate cash payout and is reduced by any forfeitures. Effective January 1, 2005, new awards granted pursuant to the PSSP will be payable in Company common stock rather than in cash.

The RSA program allows the Company to grant shares of restricted common stock to officers and key employees of the Company. 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. The weighted-average price of restricted shares at the grant date was $46.95, $39.53 and $44.27 in 2004, 2003 and 2002, respectively. Compensation expense is reduced by any forfeitures. Restricted shares are not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. Changes in restricted stock shares outstanding were:

	2004	2003	2002
Beginning balance	**944,883**	950,180	674,511
Granted	**154,500**	180,200	365,920
Vested	**(367,107)**	(151,677)	(75,200)
Forfeited	**(87,100)**	(33,820)	(15,051)
Ending balance	**645,176**	944,883	950,180

The total amount expensed for other stock-based compensation plans was $10 million, $27 million and $17 million in 2004, 2003 and 2002, respectively.

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 basic and dilutive purposes is as follows:

(in millions)	2004	2003	2002
Weighted-average common shares – basic	**242.2**	237.2	217.2
Restricted stock awards	**.8**	1.0	.8
Stock options	**.1**	–	.2
Weighted-average shares – fully diluted	**243.1**	238.2	218.2

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 of these shares totaled 3.6 million, 4.1 million and 4.8 million for the years ended December 31, 2004, 2003 and 2002, respectively. There were 3.0 million, 5.3 million and 92 thousand stock options outstanding at December 31, 2004, 2003 and 2002, 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 are as follows:

(in millions)	2004	2003
Loss on cash flow hedges	**$ (28)**	$ (36)
Minimum pension liability adjustments	**(142)**	(16)
Foreign currency translation and other	**6**	2
Total accumulated other comprehensive loss	**$ (164)**	$ (50)

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

All of the Company's preferred stock was issued by its subsidiaries and was not subject to mandatory redemption. Preferred stock outstanding at December 31, 2004 and 2003 consisted of the following:

(in millions, except share data and par value)	
Progress Energy Carolinas, Inc.	
Authorized – 300,000 shares, cumulative, $100 par value Preferred Stock; 20,000,000 shares, cumulative, $100 par value Serial Preferred Stock	
$5.00 Preferred – 236,997 shares outstanding (redemption price $110.00)	$ 24
$4.20 Serial Preferred – 100,000 shares outstanding (redemption price $102.00)	10
$5.44 Serial Preferred – 249,850 shares outstanding (redemption price $101.00)	25
	$ 59
Progress Energy Florida, Inc.	
Authorized – 4,000,000 shares, cumulative, $100 par value Preferred Stock; 5,000,000 shares, cumulative, no par value Preferred Stock; 1,000,000 shares, $100 par value Preference Stock;	
$100 par value Preferred Stock:	
4.00% – 39,980 shares outstanding (redemption price $104.25)	$ 4
4.40% – 75,000 shares outstanding (redemption price $102.00)	8
4.58% – 99,990 shares outstanding (redemption price $101.00)	10
4.60% – 39,997 shares outstanding (redemption price $103.25)	4
4.75% – 80,000 shares outstanding (redemption price $102.00)	8
	$ 34
Total Preferred Stock of Subsidiaries	$ 93

13. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31, the Company's long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2004):

(in millions)		2004	2003
Progress Energy, Inc.			
Senior unsecured notes, maturing 2006-2031	6.90%	$ 4,300	$ 4,800
Draws on revolving credit agreement, expiring 2009	3.19%	160	–
Unamortized fair value hedge gain, net		12	19
Unamortized premium and discount, net		(23)	(27)
		4,449	4,792
Progress Energy Carolinas, Inc.			
First mortgage bonds, maturing 2005-2033	6.33%	1,600	1,900
Pollution control obligations, maturing 2017-2024	1.98%	669	708
Unsecured notes, maturing 2012	6.50%	500	500
Medium-term notes, maturing 2008	6.65%	300	300
Unamortized premium and discount, net		(19)	(22)
		3,050	3,386
Progress Energy Florida, Inc.			
First mortgage bonds, maturing 2008-2033	5.60%	1,330	1,330
Pollution control obligations, maturing 2018-2027	1.67%	241	241
Medium-term notes, maturing 2005-2028	6.76%	337	379
Draws on revolving credit agreement, expiring 2006	2.95%	55	–
Unamortized premium and discount, net		(3)	(3)
		1,960	1,947
Florida Progress Funding Corporation (See Note 19)			
Debt to affiliated trust, maturing 2039	7.10%	309	309
Unamortized premium and discount, net		(39)	(39)
		270	270
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2006-2008	6.84%	140	165
Miscellaneous notes		1	1
		141	166
Progress Genco Ventures, LLC			
Variable rate project financing, maturing 2007		–	241
Current portion of long-term debt		(349)	(868)
Total long-term debt		$ 9,521	$ 9,934

At December 31, 2004, the Company had committed lines of credit used to support its commercial paper borrowings. The Progress Energy five-year credit facility and the PEF three-year credit facility are included in long-term debt. All other credit facilities are included in short-term obligations. At December 31, 2004, the Company had $260 million outstanding under its credit facilities classified as short-term obligations at a weighted-average interest rate of 3.18%. No amount was outstanding under the Company's committed lines of credit at December 31, 2003. The Company is required to pay minimal annual commitment fees to maintain its credit facilities.

The following table summarizes the Company's credit facilities:

(in millions) Company	Description	Total	Outstanding	Available
Progress Energy, Inc.	5-Year (expiring 8/5/09)	$ 1,130	$ 160	$ 970
Progress Energy Carolinas, Inc.	364-Day (expiring 7/27/05)	165	90	75
Progress Energy Carolinas, Inc.	3-Year (expiring 7/31/05)	285	–	285
Progress Energy Florida, Inc.	364-Day (expiring 3/29/05)	200	170	30
Progress Energy Florida, Inc.	3-Year (expiring 4/01/06)	200	55	145
Less: amounts reserved(a)				(574)
Total credit facilities		$ 1,980	$ 475	$ 931

(a) To the extent amounts are reserved for commercial paper outstanding or backing letters of credit, they are not available for additional borrowings.

At December 31, 2004 and 2003, the Company had $424 million and $4 million, respectively, of outstanding commercial paper and other short-term debt classified as short-term obligations. The weighted-average interest rates of such short-term obligations at December 31, 2004 and 2003 were 2.77% and 2.25%, respectively. At December 31, 2004, the Company has reserved $150 million of its lines of credit for backing of letters of credit.

Both Progress Energy and PEF have an uncommitted bank bid facility authorizing them to borrow and reborrow, and have loans outstanding at any time, up to $300 million and $100 million, respectively. These bank bid facilities were not drawn at December 31, 2004.

On January 31, 2005, Progress Energy, Inc., entered into a new $600 million revolving credit agreement, which expires December 30, 2005. This facility was added to provide additional liquidity during 2005 due in part to storm restoration costs incurred in Florida during 2004. The credit agreement includes a defined maximum total debt to total capital ratio of 68% and a minimum interest coverage ratio of 2.5 to 1. The credit agreement also contains various cross-default and other acceleration provisions. On February 4, 2005, $300 million was drawn under the new facility to reduce commercial paper and bank loans outstanding.

The combined aggregate maturities of long-term debt for 2005 through 2009 are approximately $349 million, $963 million, $674 million, $827 million and $560 million, respectively.

B. Covenants and Default Provisions

FINANCIAL COVENANTS

Progress Energy's, PEC's and PEF's credit lines contain various terms and conditions that could affect the Company's ability to borrow under these facilities. These include maximum debt to total capital ratios, interest coverage tests, 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, 2004, the maximum and calculated ratios for the companies, pursuant to the terms of the agreements, are as follows:

Company	Maximum Ratio	Actual Ratio (a)
Progress Energy, Inc.	65%	60.7%
Progress Energy Carolinas, Inc.	65%	52.3%
Progress Energy Florida, Inc.	65%	50.8%

(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's 364-day credit facility and both PEF's 364-day and three-year credit facilities have a financial covenant for interest coverage. The covenants require Progress Energy's and PEF's earnings before interest, taxes, and depreciation and amortization to interest expense ratio to be at least 2.5 to 1 and 3 to 1, respectively. For the year ended December 31, 2004, the ratios were 4.00 to 1 and 7.93 to 1 for the Company and PEF, respectively.

In March 2005, Progress Energy, Inc.'s five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65% to 68% in anticipation of the potential impacts of proposed accounting rules for uncertain tax positions. See Notes 2 and 23E.

MATERIAL ADVERSE CHANGE CLAUSE

The credit facilities of Progress Energy, PEC, and PEF include a provision under which lenders could refuse to advance funds in the event of a material adverse change (MAC) in the borrower's financial condition. Pursuant to the terms of Progress Energy's five-year credit facility, even in the event of a MAC, Progress Energy may continue to borrow funds so long as the proceeds are used to repay maturing commercial paper balances.

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of $10 million. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of $10 million, the lenders could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. Progress Energy's cross-default provision applies only to Progress Energy and its significant subsidiaries (i.e., PEC, Florida Progress, PEF, Progress Capital Holdings, Inc. (PCH) and Progress Fuels).

Additionally, certain of Progress Energy's long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of $25 million; these provisions apply only to other obligations of Progress Energy, primarily commercial paper issued by the holding company, 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 the Company's indebtedness also limit its ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither Progress Energy'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's subsidiaries as outlined below.

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, 2004, 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% of net income available for dividends if common stock equity falls below 25% of total capitalization, and to 50% if common stock equity falls below 20%. At December 31, 2004, PEC's common stock equity was approximately 52.2% of total capitalization.

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, 2004, 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 (a) all credits to retained earnings since April 30, 1944, plus (b) all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus.

PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75% of net income available for dividends if common stock equity falls below 25% of total capitalization, and to 50% if common stock equity falls below 20%. On December 31, 2004, PEF's common stock equity was approximately 54.4% 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, 2004, PEC and PEF had a total of approximately $3.84 billion 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. Progress Genco Ventures, LLC (Genco) Bank Facility

In December 2004, Genco repaid its bank facility and recorded a $9 million pre-tax loss ($6 million after-tax) in other, net on the extinguishment. At that time, the related $195 million notional amount of interest rate collars in place to hedge floating interest rate exposure on the bank facility was terminated and pre-tax deferred losses of $6 million ($4 million after-tax) were reclassified into earnings in other, net due to the discontinuance of the hedges. The facility was obtained to be used exclusively for expansion of its nonregulated generation portfolio. Borrowings under this facility were secured by the assets in the generation portfolio. The facility was for up to $260 million, of which $241 million had been drawn at December 31, 2003. Borrowings under the facility were restricted for the operations, construction, repayments and other related charges of the credit facility for the development projects. Cash held and restricted to operations was $24 million at December 31, 2003, and was included in other current assets. Cash held and restricted for long-term purposes was $9 million at December 31, 2003, respectively, and was included in other assets and deferred debits on the Consolidated Balance Sheets.

E. Guarantees of Subsidiary Debt

See Note 19 on related party transactions for a discussion of obligations guaranteed or secured by affiliates.

F. Hedging Activities

Progress Energy uses interest rate derivatives to adjust the fixed and variable rate components of its debt portfolio and to hedge cash flow risk related to commercial paper and to fixed rate debt to be issued in the future. See discussion of risk management activities and derivative transactions at Note 18.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts of cash and cash equivalents and short-term obligations approximate fair value due to the short maturities of these instruments. At December 31, 2004, and 2003, investments in company-owned life insurance and other benefit plan assets, with carrying amounts of approximately $220 million and $210 million, respectively, 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. Other instruments, including short-term investments, are presented at fair value in accordance with GAAP. The carrying amount of the Company's long-term debt, including current maturities, was $9.870 billion and $10.802 billion at December 31, 2004 and 2003, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $10.843 billion and $11.917 billion at December 31, 2004 and 2003, respectively.

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 6D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents. 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.

15. INCOME TAXES

Deferred income taxes have been provided for temporary differences. These occur when there are differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes under SFAS No. 109, "Accounting for Income Taxes," (SFAS No. 109) is different from the recovery of taxes by PEC and PEF 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.

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

(in millions)	2004	2003
Current deferred tax asset		
Unbilled revenue	$ 35	$ 18
Other	86	69
Total current deferred tax asset	121	87
Noncurrent deferred tax asset (liability)		
Investments	73	8
Supplemental executive retirement plans	31	30
Other post-employment benefits (OPEB)	126	119
Other pension plans	(15)	(97)
Goodwill	34	46
Accumulated depreciation and property cost differences	(1,374)	(1,436)
Deferred costs	(13)	26
Deferred storm costs	(113)	–
Deferred fuel	(55)	31
Federal income tax credit carry forward	779	683
State net operating loss carry forward	47	42
Valuation allowance	(47)	(42)
Miscellaneous other temporary differences, net	43	(16)
Total noncurrent deferred tax liabilities	(484)	(606)
Less amount included in other assets and deferred debits	10	9
Net noncurrent deferred tax liabilities	$ (494)	$ (615)

Total deferred income tax liabilities were $2,797 million and $2,662 million at December 31, 2004 and 2003, respectively. Total deferred income tax assets were $2,434 million and $2,143 million at December 31, 2004 and 2003, respectively. Total noncurrent income tax liabilities on the Consolidated Balance Sheets at December 31, 2004 and 2003 include $105 million and $86 million, respectively, related to probable tax liabilities on which the Company accrues interest that would be payable with the related tax amount in future years.

The federal income tax credit carry forward at December 31, 2004, consists of $749 million of alternative minimum tax credit with an indefinite carry forward period and $30 million of general business credit with a carry forward period that will begin to expire in 2020.

As of December 31, 2004, the Company had a state net operating loss carry forward of $79 million, which will begin to expire in 2007.

The Company established additional valuation allowances of $5 million during 2004 and 2003 and $12 million during 2002, due to the uncertainty of realizing certain future state tax benefits. The Company believes 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. Progress Energy decreased its 2004 beginning of the year valuation allowance by $8 million for a change in circumstances related to net operating losses.

The Company establishes accruals for certain tax contingencies when, despite the belief that the Company's tax return positions are fully supported, the Company believes that certain positions may be challenged and that it is probable the Company's positions may not be fully sustained. The Company is under continuous examination by the Internal Revenue Service and other tax authorities and accounts for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2004 and 2003, respectively, the Company had recorded $60 million and $56 million of tax contingency reserves, excluding accrued interest and penalties, which are included in other current liabilities on the Consolidated Balance Sheets. Considering all tax contingency reserves, the Company does not expect the resolution of these matters to have a material impact on its financial position or result of operations. All tax contingency reserves relate to capitalization and basis issues and do not relate to any potential disallowances of tax credits from synthetic fuel production (See Note 23E).

Reconciliations of the Company's effective income tax rate to the statutory federal income tax rate are:

	2004	2003	2002
Effective income tax rate	**13.5%**	(15.8)%	(40.0)%
State income taxes, net of federal benefit	**(6.9)**	(3.3)	(8.2)
AFUDC amortization	**(0.5)**	(1.4)	(5.2)
Federal tax credits	**25.6**	50.4	78.0
Investment tax credit amortization	**1.6**	2.3	4.7
ESOP dividend deduction	**1.8**	2.1	3.8
Other differences, net	**(0.1)**	0.7	1.9
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense (benefit) applicable to continuing operations is comprised of:

(in millions)	2004	2003	2002
Current – federal	**$ 127**	$ 127	$ 195
state	**76**	54	67
Deferred – federal	**(84)**	(255)	(379)
state	**10**	(21)	(23)
Investment tax credit	**(14)**	(16)	(18)
Total income tax expense (benefit)	**$ 115**	$ (111)	$ (158)

The company has recognized tax benefits from state net operating loss carry forwards in the amount of $7 million during 2004 and $3 million during 2003 and 2002.

The Company, through its subsidiaries, is a majority owner in five entities and a minority owner in one entity that owns facilities that produce synthetic fuel as defined under the Internal Revenue Code (Code). The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 if certain requirements are satisfied (See Note 23E).

16. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of FPC during 2000, the Company issued 98.6 million contingent value obligations (CVOs). Each CVO represents the right to receive contingent payments based on the performance of four synthetic fuel facilities purchased by subsidiaries of FPC 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, 2004 and 2003, was $13 million and $23 million, respectively.

17. BENEFIT PLANS

A. Postretirement Benefits

The Company and some of its subsidiaries have a noncontributory defined benefit retirement (pension) plan for substantially all full-time employees. The Company also has supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, the Company and some of its subsidiaries provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. The Company uses a measurement date of December 31 for its pension and OPEB plans.

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

(in millions)	Pension Benefits 2004	Pension Benefits 2003	Pension Benefits 2002	Other Postretirement Benefits 2004	Other Postretirement Benefits 2003	Other Postretirement Benefits 2002
Service cost	$ 54	$ 52	$ 45	$ 12	$ 15	$ 13
Interest cost	110	108	106	31	33	32
Expected return on plan assets	(155)	(144)	(161)	(5)	(4)	(5)
Amortization of actuarial (gain) loss	21	25	2	4	5	1
Other amortization, net	–	–	–	1	4	4
Net periodic cost / (benefit)	$ 30	$ 41	$ (8)	$ 43	$ 53	$ 45
Additional cost / (benefit) recognition (Note 17B)	(16)	(18)	(7)	2	2	2
Net periodic cost / (benefit) recognized	$ 14	$ 23	$ (15)	$ 45	$ 55	$ 47

The net periodic cost for other postretirement benefits decreased during 2004 due to the implementation of FASB Staff Position 106-2 (See Note 2). In addition to the net periodic cost and benefit reflected above, in 2003 the Company 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.

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% 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, the Company uses a five-year averaging method for a portion of its pension assets and fair value for the remaining portion. The Company has historically used the five- year averaging method. When the Company acquired Florida Progress in 2000, it retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets.

Reconciliations of the changes in the plans' benefit obligations and the plans' funded status are:

(in millions)	Pension Benefits 2004	Pension Benefits 2003	Other Postretirement Benefits 2004	Other Postretirement Benefits 2003
Projected benefit obligation at January 1	$ 1,772	$ 1,694	$ 472	$ 514
Service cost	54	52	12	15
Interest cost	110	108	31	33
Disposition of NCNG	–	(39)	–	(13)
Benefit payments	(98)	(94)	(23)	(24)
Plan amendment	21	–	–	–
Actuarial loss (gain)	102	51	46	(53)
Obligation at December 31	1,961	1,772	538	472
Fair value of plan assets at December 31	1,774	1,631	70	65
Funded status	(187)	(141)	(468)	(407)
Unrecognized transition obligation	–	–	10	25
Unrecognized prior service cost	24	4	6	7
Unrecognized net actuarial loss	530	505	94	40
Minimum pension liability adjustment	(470)	(23)	–	–
Prepaid (accrued) cost at December 31, net (Note 17B)	$ (103)	$ 345	$ (358)	$ (335)

The 2003 OPEB obligation information above has been restated due to the implementation of FASB Staff Position 106-2 (See Note 2).

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 net prepaid pension cost of $345 million at December 31, 2003, is recognized in the Consolidated Balance Sheets as prepaid pension cost of $462 million and accrued benefit cost of $117 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 $1.72 billion and $125 million at December 31, 2004 and 2003, respectively. Those plans had accumulated benefit obligations totaling $1.71 billion and $117 million at December 31, 2004 and 2003, respectively, $1.57 billion of plan assets at December 31, 2004, and no plan assets at December 31, 2003. The total accumulated benefit obligation for pension plans was $1.90 billion and $1.72 billion at December 31, 2004 and 2003, respectively. The accrued OPEB cost is included in accrued pension and other benefits in the Consolidated Balance Sheets.

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 17B), a $67 million charge to a regulatory asset pursuant to a recent FPSC order and a pre-tax charge of $229 million to accumulated other comprehensive loss, a component of common stock equity. A minimum pension liability adjustment of $23 million, related to the supplementary defined benefit pension plans, was recorded at December 31, 2003. This adjustment is offset by a corresponding pre-tax amount in accumulated other comprehensive loss.

Reconciliations of the fair value of plan assets are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2004**	2003	**2004**	2003
Fair value of plan assets January 1	**$ 1,631**	$ 1,364	**$ 65**	$ 52
Actual return on plan assets	**211**	391	**8**	12
Disposition of NCNG	**–**	(35)	**–**	–
Benefit payments	**(98)**	(94)	**(23)**	(24)
Employer contributions	**30**	5	**20**	25
Fair value of plan assets at December 31	**$ 1,774**	$ 1,631	**$ 70**	$ 65

In the table above, substantially all employer contributions represent benefit payments made directly from Company assets except for the 2004 pension amount. The remaining benefits payments were made directly from plan assets. In 2004, the Company made a required contribution of approximately $24 million directly to pension plan assets. The OPEB benefit payments represent the net Company cost after participant contributions. Participant contributions represent approximately 20% of gross benefit payments.

The asset allocation for the Company's plans at the end of 2004 and 2003 and the target allocation for the plans, by asset category, are as follows:

	Pension Benefits			Other Postretirement Benefits		
	Target Allocations	Percentage of Plan Assets at Year End		Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2005	**2004**	2003	2005	**2004**	2003
Equity – domestic	48%	**47%**	49%	34%	**34%**	35%
Equity – international	15%	**21%**	22%	11%	**15%**	16%
Debt – domestic	12%	**9%**	11%	37%	**35%**	37%
Debt – international	10%	**11%**	11%	7%	**8%**	7%
Other	15%	**12%**	7%	11%	**8%**	5%
Total	100%	**100%**	100%	100%	**100%**	100%

The Company sets 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, the Company employs external investment managers who have complementary investment philosophies and approaches. Tactical shifts (plus or minus 5%) 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.

In 2005, the Company expects to make no required 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 2005 through 2009 and in total for 2010-2014, in millions, are approximately $113, $110, $115, $124, $131 and $794, respectively. The expected benefit payments for the OPEB plan for 2005 through 2009 and in total for 2010-2014, in millions, are approximately $32, $34, $37, $39, $41 and $230, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from Company assets. The benefit payment amounts reflect the net cost to the Company after any participant contributions. The Company expects to begin receiving prescription drug-related federal subsidies in 2006 (See Note 2), and the expected subsidies for 2006 through 2009 and in total for 2010-2014, in millions, are approximately $3, $3, $3, $4 and $24, respectively. The expected benefit payments above do not reflect the potential effects of a 2005 voluntary enhanced retirement program (See Note 24).

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2004	2003	2004	2003
Discount rate	5.90%	6.30%	5.9%	6.30%
Rate of increase in future compensation				
Bargaining	3.50%	3.50%	–	–
Supplementary plans	5.25%	5.00%	–	–
Initial medical cost trend rate for pre-Medicare benefits	–	–	7.25%	7.25%
Initial medical cost trend rate for post-Medicare benefits	–	–	7.25%	7.25%
Ultimate medical cost trend rate	–	–	5.00%	5.25%
Year ultimate medical cost trend rate is achieved	–	–	2008	2009

The Company's primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4. Therefore, effective December 31, 2003, the Company 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.

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

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2004	2003	2002	2004	2003	2002
Discount rate	6.30%	6.60%	7.50%	6.30%	6.60%	7.50%
Rate of increase in future compensation						
Bargaining	3.50%	3.50%	3.50%	–	–	–
Nonbargaining	–	4.00%	4.00%	–	–	–
Supplementary plans	5.00%	4.00%	4.00%	–	–	–
Expected long-term rate of return on plan assets	9.25%	9.25%	9.25%	8.50%	8.45%	8.20%

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 Company has chosen to use an expected long-term rate of 9.25%.

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. Assuming a 1% increase in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2004 would increase by $1 million, and the OPEB obligation at December 31, 2004, would increase by $30 million. Assuming a 1% decrease in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2004 would decrease by $1 million, and the OPEB obligation at December 31, 2004, would decrease by $26 million.

B. FPC Acquisition

During 2000, the Company completed the acquisition of FPC. FPC's pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of FPC's nonbargaining unit benefit plans were merged with those of the Company 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 table above has a corresponding regulatory asset at December 31, 2004, and 2003 (See Note 8A). In addition, a portion of the prepaid pension cost reflected in the table above has a corresponding regulatory liability (See Note 8A). Pursuant to its rate treatment, PEF recognized additional periodic pension credits and additional periodic OPEB costs, as indicated in the net periodic cost information above.

18. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

Under its risk management policy, the Company 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. The Company minimizes 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 the consolidated financial position or consolidated results of operations of the Company.

A. Commodity Derivatives

GENERAL

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

During 2003 the FASB reconsidered an interpretation of SFAS No. 133 related to the pricing of contracts that include broad market indices (e.g., CPI). In particular, that guidance discussed whether the pricing in a contract that contains broad market indices could qualify as a normal purchase or sale (the normal purchase or sale term is a defined accounting term, and may not, in all cases, indicate whether the contract would be "normal" from an operating entity viewpoint). The FASB issued final superseding guidance (DIG Issue C20) on this issue effective October 1, 2003, for the Company. DIG Issue C20 specifies new pricing-related criteria for qualifying as a normal purchase or sale, and it required a special transition adjustment as of October 1, 2003.

PEC determined that it had one existing "normal" contract that was affected by DIG Issue C20. Pursuant to the provisions of DIG Issue C20, PEC recorded a pre-tax fair value loss transition adjustment of $38 million ($23 million after-tax) in the fourth quarter of 2003, which was reported as a cumulative effect of a change in accounting principle. The subject contract meets the DIG Issue C20 criteria for normal purchase or sale and, therefore, was designated as a normal purchase as of October 1, 2003. The original liability of $38 million associated with the fair value loss is being amortized to earnings over the term of the related contract. At December 31, 2004 and 2003, the remaining liability was $26 million and $35 million, respectively.

ECONOMIC DERIVATIVES

Derivative products, primarily electricity and natural gas contracts, are entered into for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. The Company manages open positions with strict policies that limit its exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material to results of operations during 2004, 2003 or 2002, and the Company did not have material outstanding positions in such contracts at December 31, 2004 and 2003.

In 2004, PEF entered into derivative instruments related to its exposure to price fluctuations on fuel oil purchases. At December 31, 2004, the fair values of these 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. These instruments receive regulatory accounting treatment. Gains are recorded in regulatory liabilities and losses are recorded in regulatory assets.

CASH FLOW HEDGES

Progress Energy's 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 for the Company's forecasted purchases and sales. At December 31, 2004, the maximum period over which the Company is hedging exposures to the price variability of natural gas is 10 years.

The total fair value of commodity cash flow hedges at December 31, 2004 and 2003 was as follows:

(millions of dollars)	2004	2003
Fair value of assets	$ –	$ –
Fair value of liabilities	(15)	(12)
Fair value, net	$ (15)	$ (12)

The ineffective portion of commodity cash flow hedges was not material to the Company's results of operations for 2004, 2003 or 2002. At December 31, 2004, there were $9 million of after-tax deferred losses in accumulated other comprehensive income (OCI), of which $5 million is expected to be reclassified to earnings during the next 12 months as the hedged transactions occur. Gains and losses are recorded net in operating revenues. As part of the divestiture of Winchester Production Company, Ltd., assets in 2004, $7 million of after-tax deferred losses were reclassified into earnings due to discontinuance of the related cash flow hedges and recorded against the gain on sale. Due to the volatility of the commodities markets, the value in OCI is subject to change prior to its reclassification into earnings.

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

The Company uses cash flow hedging strategies to hedge variable interest rates on long-term and short-term debt and to hedge interest rates with regard to future fixed-rate debt issuances. Gains and losses are recorded in OCI and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. The Company uses fair value hedging strategies to manage its exposure to fixed interest rates on long-term debt. 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.

The fair values of open position interest rate hedges at December 31, 2004 and 2003 were as follows:

(in millions)	2004	2003
Interest rate cash flow hedges	$ (2)	$ (6)
Interest rate fair value hedges	$ 3	$ (4)

CASH FLOW HEDGES

The following table presents selected information related to the Company's interest rate cash flow hedges included in accumulated OCI at December 31, 2004:

Accumulated Other Comprehensive Income/(Loss), net of tax[a] (millions of dollars)	Portion Expected to be Reclassified to Earnings during the Next 12 Months[b]
$ (19)	$ (4)

[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.

As of December 31, 2004, PEC had $110 million notional amount of pay-fixed forward swaps to hedge its exposure to interest rates with regard to future issuances of debt (pre-issue hedges) and $21 million notional amount of pay-fixed forward starting swaps to hedge its exposure to interest rates with regard to an upcoming railcar lease. On February 4, 2005, PEC entered another $50 million notional amount of its pre-issue hedges. All the swaps have a computational period of 10 years. PEC held no interest rate cash flow hedges at December 31, 2003. The ineffective portion of interest rate cash flow hedges was not material to the Company's results of operations for 2004 and 2003.

In December 2004, Progress Ventures, Inc. (PVI), a wholly owned subsidiary of Progress Energy, terminated $195 million notional amount of interest rate collars in place to hedge floating interest rate exposure associated with variable-rate long-term debt. The related debt was also extinguished in December 2004 (See Note 13). Pre-tax deferred losses of $6 million ($4 million after-tax) were reclassified into earnings in other, net due to discontinuance of these cash flow hedges.

At December 31, 2004 and 2003, Progress Energy, Inc., held interest rate cash flow hedges, with a total notional amount of $200 million and $400 million, respectively, related to projected outstanding balances of commercial paper. The fair value of the hedges at December 31, 2004, was not material to the Company's financial condition and at December 31, 2003, was $5 million. The hedges held at December 31, 2003, were terminated during the year. Amounts in accumulated other comprehensive income related to these terminated hedges will be reclassified to earnings as the hedged interest payments occur.

FAIR VALUE HEDGES

As of December 31, 2004 and 2003, Progress Energy had $150 million notional amount and $850 million notional amount, respectively, of fixed rate debt swapped to floating rate debt by executing interest rate derivative agreements. These agreements expire on various dates through March 2011. During 2004, Progress Energy entered into $350 million notional amount and terminated $1.05 billion notional amount of interest rate swap agreements.

At December 31, 2004 and 2003, the Company had $9 million and $23 million, 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 2011 coinciding with the maturities of the related debt instruments.

The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by a counterparty, the risk in these transactions is the cost of replacing the agreements at current market rates.

19. RELATED PARTY TRANSACTIONS

As a part of normal business, Progress Energy and certain subsidiaries 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. As of December 31, 2004, Progress Energy and its subsidiaries' guarantees include: $270 million supporting commodity transactions, $181 million to support nuclear decommissioning, $536 million related to power supply agreements and $182 million for guarantees supporting other agreements of subsidiaries. Progress Energy also purchased $92 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $50 million. Florida Progress also fully guarantees the medium term notes outstanding for Progress Capital, a wholly owned subsidiary of Florida Progress (See Note 13). At December 31, 2004, management does not believe conditions are likely for significant performance under these agreements. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Balance Sheets.

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 $331 million, $346 million and $329 million for the years ended December 31, 2004, 2003 and 2002, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income.

Florida Progress Funding Corporation (Funding Corp.) $309 million 7.10% Junior Subordinated Deferrable Interest Notes (Subordinated Notes) are due to FPC Capital I (the Trust). The Trust was established for the sole purpose of issuing $300 million Preferred Securities and using the proceeds thereof to purchase from Funding Corp. its Subordinated Notes due 2039. The Company has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, the Company has 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 (Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by the Company of the Trust's obligations under the Preferred Securities. The Subordinated Notes and the Notes Guarantee are the sole assets of the Trust. 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.

The Company sold NCNG to Piedmont Natural Gas Company, Inc. on September 30, 2003 (See Note 4E). Prior to disposition, NCNG sold natural gas to affiliates. During the years ended December 31, 2003 and 2002, sales of natural gas to affiliates amounted to $11 million and $20 million, respectively. These revenues are included in discontinued operations on the Consolidated Statements of Income.

20. FINANCIAL INFORMATION BY BUSINESS SEGMENT

The Company currently provides services through the following business segments: PEC Electric, PEF, Fuels, CCO and Rail Services. Prior to 2004, other nonregulated business activities were reported separately in the Other segment. These reportable segment changes reflect the current reporting structure. For comparative purposes, the results have been restated to align with the current presentation.

PEC Electric and PEF are primarily engaged in the generation, transmission, distribution and sale of electric energy in portions of North Carolina, South Carolina and Florida. These electric operations are subject to the rules and regulations of the FERC, the NCUC, the SCPSC and the FPSC. These electric operations also distribute and sell electricity to other utilities, primarily on the east coast of the United States.

Fuels operations, which are located throughout the United States, are involved in natural gas drilling and production, coal terminal services, coal mining, synthetic fuel production and fuel transportation and delivery.

CCO's operations, which are located in the southeastern United States, include nonregulated electric generation operations and marketing activities.

Rail Services' operations include railcar repair, rail parts reconditioning and sales, railcar leasing and sales and scrap metal recycling. These activities include maintenance and reconditioning of salvageable scrap components of railcars, locomotive repair and right-of-way maintenance. Rail Services' operations are located in the United States, Canada and Mexico.

In addition to these reportable operating segments, the Company has Corporate and other activities that include holding company and service company operations as well as other nonregulated business areas. These nonregulated business areas include telecommunications and energy service operations 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." Included in the 2004 losses is a $43 million pre-tax ($29 million after-tax) settlement agreement that SRS reached with the San Francisco United School District related to civil proceedings. Included in the 2002 losses are asset impairments and certain other after-tax charges related to the telecommunications operations of $225 million. The operations of NCNG were reclassified to discontinued operations and therefore are not included in the results from continuing operations during the periods reported. The profit or loss of the identified segments plus the loss of Corporate and Other represents the Company's total income from continuing operations.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between Fuels and PEF, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and Fuels are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. The profits for all three years presented were not significant.

(in millions)	PEC Electric	PEF	Fuels	CCO	Rail Services	Corporate and Other	Eliminations	Totals
Year ended December 31, 2004								
Revenues								
Unaffiliated	$ 3,628	$ 3,525	$ 1,179	$ 240	$ 1,130	$ 70	$ –	$ 9,772
Intersegment	–	–	331	–	1	441	(773)	–
Total revenues	3,628	3,525	1,510	240	1,131	511	(773)	9,772
Depreciation and amortization	570	281	93	58	21	45	–	1,068
Total interest charges, net	192	114	22	17	27	361	(86)	647
Gain on sale of assets	–	–	54	–	–	3	–	57
Income tax expense (benefit) (a)	237	174	(230)	(1)	15	(80)	–	115
Segment profit (loss)	464	333	180	(4)	16	(236)	–	753
Total assets	10,590	7,924	986	1,709	596	17,741	(13,553)	25,993
Capital and investment expenditures	519	480	157	25	40	14	–	1,235
Year ended December 31, 2003								
Revenues								
Unaffiliated	$ 3,589	$ 3,152	$ 928	$ 170	$ 846	$ 56	$ –	$ 8,741
Intersegment	–	–	346	–	1	446	(793)	–
Total revenues	3,589	3,152	1,274	170	847	502	(793)	8,741
Depreciation and amortization	562	307	80	42	20	29	–	1,040
Total interest charges, net	197	91	23	4	29	356	(72)	628
Impairment of long-lived assets and investments	11	–	17	–	–	10	–	38
Income tax expense (benefit) (a)	238	147	(415)	8	2	(46)	(45)	(111)
Segment profit (loss)	515	295	235	20	(1)	(253)	–	811
Total assets	10,748	7,280	1,142	1,747	586	17,955	(13,365)	26,093
Capital and investment expenditures	445	526	309	338	103	35	–	1,756
Year ended December 31, 2002								
Revenues								
Unaffiliated	$3,539	$3,062	$607	$92	$714	$77	$ –	$8,091
Intersegment	–	–	329	–	5	418	(752)	–
Total revenues	3,539	3,062	936	92	719	495	(752)	8,091
Depreciation and amortization	524	295	47	20	20	32	–	938
Total interest charges, net	212	106	24	(12)	33	351	(81)	633
Impairment of long-lived assets and investments	–	–	–	–	59	330	–	389
Income tax expense (benefit) (a)	237	163	(373)	16	(16)	(191)	6	(158)
Segment profit (loss)	513	323	176	27	(42)	(445)	–	552
Total assets	10,139	6,678	934	1,452	529	15,872	(11,886)	23,718
Capital and investment expenditures	619	550	170	682	8	73	–	2,102

(a) Amounts include income tax benefit reallocation from holding company to profitable subsidiaries according to an SEC order.

Geographic Data

(in millions)	U.S.	Canada	Mexico	Consolidated
2004				
Consolidated revenues	**$ 9,644**	**$ 112**	**$ 16**	**$ 9,772**
2003				
Consolidated revenues	$ 8,624	$ 103	$ 14	$ 8,741
2002				
Consolidated revenues	$ 7,984	$ 93	$ 14	$ 8,091

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. The components of other, net as shown on the Consolidated Statements of Income for the years ended December 31 are as follows:

(in millions)	2004	2003	2002
Other income			
Nonregulated energy and delivery services income	**$ 32**	$ 27	$ 33
DIG Issue C20 amortization (Note 18A)	**9**	2	–
Contingent value obligation unrealized gain (Note 16)	**9**	–	28
Investment gains	**–**	5	–
AFUDC equity	**11**	14	8
Gain on sale of property and partnership investment	**12**	25	12
Other	**34**	17	42
Total other income	**$ 107**	$ 90	$ 123
Other expense			
Nonregulated energy and delivery services expenses	**$ 20**	$ 20	$ 29
Donations	**10**	12	19
Investment losses	**6**	–	–
Contingent value obligation unrealized loss (Note 16)	**–**	9	–
Loss from equity investments	**6**	40	21
Loss on debt extinguishment and interest rate collars (Note 13D)	**15**	–	–
Other	**42**	25	27
Total other expense	**$ 99**	$ 106	$ 96
Other, net	**$ 8**	$ (16)	$ 27

Nonregulated energy and delivery services include power protection services and mass market programs (surge protection, appliance services and area light sales) and delivery, transmission and substation work for other utilities.

22. ENVIRONMENTAL MATTERS

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

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North and South Carolina, have similar types of legislation. The Company and its subsidiaries are periodically notified by regulators including the EPA and various state agencies of their involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which the Company has been notified by the EPA, the State of North Carolina or the State of Florida of its potential liability, as described below in greater detail. The Company also is currently in the process of assessing potential costs and exposures at other sites. For all sites, as assessments are developed and analyzed, the Company will accrue costs for the sites to the extent the costs are probable and can be reasonably estimated. A discussion of sites by legal entity follows.

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.

PEC, PEF and Progress Fuels Corporation have filed claims with the Company's general liability insurance carriers to recover costs arising from actual or potential environmental liabilities. Some claims have been settled and others are still pending. While the Company cannot predict the outcome of these matters, the outcome is not expected to have a material effect on the consolidated financial position or results of operations.

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 costs.

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, North Carolina. The EPA offered PEC and 34 other PRPs the opportunity to negotiate cleanup of the site and reimbursement of less than $2 million to the EPA for EPA's 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 Ward Transformer site.

At December 31, 2004 and 2003, 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 many years, were:

(in millions)	2004	2003
Insurance fund	$ 7	$ 9
Transferred from NCNG at time of sale	2	2
Total accrual for environmental sites	$ 9	$ 11

PEC received insurance proceeds to address costs associated with environmental liabilities related to its involvement with some sites. All eligible expenses related to these are charged against a specific fund containing these proceeds. PEC spent approximately $2 million related to environmental remediation in 2004. PEC is unable to provide an estimate of the reasonably possible total remediation costs beyond what is currently accrued because investigations have not been completed at all sites.

This accrual has been recorded on an undiscounted basis. PEC measures its liability for these sites based on available evidence including its experience in investigating and remediating environmentally impaired sites. The process often involves assessing and developing cost-sharing arrangements with other PRPs. PEC will accrue costs for the sites to the extent its 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, PEC cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is anticipated that sufficient information will become available for several sites during 2005 to allow a reasonable estimate of PEC's obligation for those sites to be made.

PEF

At December 31, 2004 and 2003, PEF'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 many years, were:

(in millions)	2004	2003
Remediation of distribution and substation transformers	$ 27	$ 12
MGP and other sites	18	6
Total accrual for environmental sites	$ 45	$ 18

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. Through 2004 PEF has reviewed a number of distribution transformer sites and substation sites. PEF expects to have completed its review of distribution transformer sites by the end of 2007 and has completed the review of substation sites in 2004. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC clause. In 2004, PEF accrued an additional $19 million due to identification of additional sites requiring remediation, and spent approximately $4 million 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. In 2004, PEF received approximately $12 million in insurance claim settlement proceeds and recorded a related accrual for associated environmental expenses. The proceeds are restricted for use in addressing costs associated with environmental liabilities. Expenditures for the year were less than $1 million.

These accruals have been recorded on an undiscounted basis. PEF measures its liability for these sites based on available evidence including its experience in investigating and remediating environmentally impaired sites. This process often includes assessing and developing cost-sharing arrangements with other PRPs. 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 advanced to the stage where a reasonable estimate of the remediation costs can be made, at this time PEF is unable to provide an estimate of its obligation to remediate these sites beyond what is currently accrued. As more activity occurs at these sites, PEF will assess the need to adjust the accruals. It is anticipated that sufficient information will become available in 2005 to make a reasonable estimate of PEF's obligation for one of the MGP sites.

The Florida Legislature passed risk-based corrective action (RBCA, known as Global RBCA) legislation in the 2003 regular session. 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 law 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. The FDEP developed the rules required by the RBCA statute, holding meetings with interested stakeholders and hosting public workshops. The rules have the potential for making future cleanups in Florida more costly to complete. The Global RBCA rule was adopted at the February 2, 2005, Environmental Review Commission hearing. The effective date of the Global RBCA rule is expected to be announced in April 2005. The Company and PEF are in the process of assessing the impact of this matter.

FLORIDA PROGRESS CORPORATION

In 2001, FPC established a $10 million accrual to address indemnities and retained an environmental liability associated with the sale of its Inland Marine Transportation business. In 2003, the accrual was reduced to $4 million based on a change in estimate. During 2004, expenditures related to this liability were not material to the Company's financial condition. As of December 31, 2004, the remaining accrual balance was approximately $3 million. FPC measures its liability for these exposures based on estimable and probable remediation scenarios.

Certain historical sites are being addressed voluntarily by FPC. An immaterial accrual has been established to address investigation expenses related to these sites. At this time, the Company cannot determine the total costs that may be incurred in connection with these sites.

RAIL

Rail Services is voluntarily addressing certain historical waste sites. At this time, the Company cannot determine the total costs that may be incurred in connection with these sites.

AIR QUALITY

Congress is considering legislation that would require reductions in air emissions of NOx, SO_2, carbon dioxide and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multi-pollutant approach to air pollution control could involve significant capital costs that could be material to the Company's consolidated financial position or results of operations. Control equipment that will be installed on North Carolina fossil generating facilities as part of the NC Clean Air legislation discussed below may address some of the issues outlined above. However, the Company cannot predict the outcome of this matter.

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 New Source Review requirements or New Source Performance Standards under the Clean Air Act. The Company was 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 other 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 cost through rate adjustments or similar mechanisms. The Company cannot predict the outcome of this matter.

In 2003, the EPA published a final rule addressing routine equipment replacement under the New Source Review program. The rule defines routine equipment replacement and the types of activities that are not subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. The rule was challenged in the Federal Appeals Court and its implementation stayed. In July 2004, the EPA announced it will reconsider certain issues arising from the final routine equipment replacement rule. The comment period closed on August 30, 2004. The Company cannot predict the outcome of this matter.

In 1998, the EPA published a final rule under Section 110 of the Clean Air Act addressing the regional transport of ozone (NOx SIP Call). Total capital expenditures to meet the requirements of the NOx SIP Call Rule in North and South Carolina could reach approximately $370 million. To date, the Company has spent approximately $282 million related to these projected amounts. Increased operation and maintenance costs relating to the NOx SIP Call are not expected to be material to the Company's results of operations. Further controls are anticipated as electricity demand increases. Parties unrelated to the Company 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 Company cannot predict the outcome of this matter in Georgia.

In 1997, the EPA issued final regulations establishing a new 8-hour ozone standard. In April 2004, the EPA identified areas that do not meet the standard. The states with identified areas, including North and South Carolina, are proceeding with the implementation of the federal 8-hour ozone standard. Both states promulgated final regulations, which will require PEC to install NOx controls under the states' programs to comply with the 8-hour standard. The costs of those controls are included in the $370 million cost estimate above. However, further technical analysis and rulemaking may result in requirements for additional controls at some units. The Company cannot predict the outcome of this matter.

In June 2002, the NC Clean Air legislation was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO2 from coal-fired power plants. Progress Energy projects that its capital costs to meet these emission targets will total approximately $895 million by the end of 2013. PEC has expended approximately $108 million of these capital costs through December 31, 2004. PEC currently has approximately 5,100 MW of coal-fired generation capacity in North Carolina that is affected by this Act. The law requires the emissions reductions to be completed in phases by 2013, and applies to each utility's total system rather than setting requirements for individual power plants. The law also freezes the utilities' base rates for five years 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 law requires PEC to amortize $569 million, representing 70% of the original cost estimate of $813 million, during the five-year rate freeze period. PEC recognized amortization of $174 million and $74 million for the years ended December 31, 2004, and 2003, respectively, and has recognized $248 million in cumulative amortization through December 31, 2004. The remaining amortization requirement of $321 million will be recorded over the three-year period ending December 31, 2007. The law 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 law, PEC entered into an agreement with the State of North Carolina to transfer to the State certain NOx and SO2 emissions allowances that result from compliance with the collective NOx and SO_2 emissions limitations set out in the law. The law also requires the State to undertake a study of mercury and carbon dioxide emissions in North Carolina. Operation and maintenance costs will increase due to the additional personnel, materials and general maintenance associated with the equipment. Operation and maintenance expenses are recoverable through base rates, rather than as part of this program. Progress Energy cannot predict the future regulatory interpretation, implementation or impact of this law.

In 1997, the EPA's Mercury Study Report and Utility Report to Congress concluded that mercury is not a risk to the average person in America and expressed uncertainty about whether reductions in mercury emissions from coal-fired power plants would reduce human exposure. Nevertheless, the EPA determined in 2000 that regulation of mercury emissions from coal-fired power plants was appropriate. In 2003, the EPA proposed alternative control plans that would limit mercury emissions from coal-fired power plants. The final rule was released on March 15, 2005. The EPA's rule establishes a mercury cap and trade program for coal-fired power plants that requires limits to be met in two phases, in 2010 and 2018. The Company is reviewing the final rule. Installation of additional air quality controls is likely to be needed to meet the mercury rule's requirements. Compliance plans and the cost to comply with the rule will be determined once the Company completes its review.

In conjunction with the proposed mercury rule, the EPA proposed a MACT standard to regulate nickel emissions from residual oil-fired units. The agency estimates the proposal will reduce national nickel emissions to approximately 103 tons. As proposed, the rule may require the Company to install additional pollution controls on its residual oil-fired units, resulting in significant capital expenditures. PEC does not have units impacted by this proposal; PEF has eight units that are affected, and they currently do not have pollution controls in place that would meet the proposed requirements of the nickel rule. The EPA expects to finalize the nickel rule in March 2005. Compliance costs will be determined following promulgation of the rule.

In December 2003, the EPA released its proposed Interstate Air Quality Rule, currently referred to as the Clean Air Interstate Rule (CAIR). The final rule was released on March 10, 2005. The EPA's rule requires 28 states and the District of Columbia, including North Carolina, South Carolina, Georgia and Florida, to reduce NOx and SO_2 emissions in order to attain preset state NOx and SO_2 emissions levels. The Company is reviewing the final rule. Installation of additional air quality controls is likely to be needed to meet the CAIR requirements. Compliance plans and the cost to comply with the rule will be determined once the Company completes its review. The air quality controls already installed for compliance with the NOx SIP Call and currently planned by the Company to comply with the NC Clean Air legislation will reduce the costs required to meet the CAIR requirements for the Company's North Carolina units.

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. The EPA has agreed to make a determination on the petition by August 1, 2005. The Company cannot predict the outcome of this matter.

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 PEC and PEF in the immediate and extended future.

After many years of litigation and settlement negotiations, the EPA adopted regulations in February 2004 to implement Section 316(b) of the Clean Water Act. These regulations became effective September 7, 2004. The purpose of these regulations is to minimize adverse environmental impacts caused by cooling water intake structures and intake systems. Over the next several years these regulations will impact the larger base load generation facilities and may require the facilities to mitigate the effects to aquatic organisms by constructing intake modifications or undertaking other restorative activities. The Company currently estimates that from 2005 through 2009 the range of its expenditures to meet the Section 316(b) requirements of the Clean Water Act will be $85 million to $115 million. The range includes $20 million to $30 million at PEC and $65 million to $85 million at PEF.

OTHER ENVIRONMENTAL MATTERS

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of carbon dioxide and other greenhouse gases. In 2004, Russia ratified the Protocol, and 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. A number of carbon dioxide emissions control proposals have been advanced in Congress. Reductions in carbon dioxide emissions to the levels specified by the Kyoto Protocol and some legislative proposals could be materially adverse to the Company's consolidated financial position or results of operations if associated costs of control or limitation cannot be recovered from customers. The Company favors the voluntary program approach recommended by the administration and continually evaluates options for the reduction, avoidance and sequestration of greenhouse gases. However, the Company cannot predict the outcome of this matter.

Progress Energy has announced its plan to issue a report on the Company's activities associated with current and future environmental requirements. The report will include a discussion of the environmental requirements that the Company currently faces and expects to face in the future, as well as an assessment of potential mandatory constraints on carbon dioxide emissions. The report will be issued by March 31, 2006.

23. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2004, the following table reflects Progress Energy's contractual cash obligations and other commercial commitments in the respective periods in which they are due:

(in millions)	2005	2006	2007	2008	2009	Thereafter
Fuel	$ 2,219	$ 1,473	$ 663	$ 229	$ 252	$ 1,270
Purchased power	473	473	479	449	416	4,614
Construction obligations	51	–	–	–	–	–
Other purchase obligations	100	70	64	41	39	268
Total	$ 2,843	$ 2,016	$ 1,206	$ 719	$ 707	$ 6,152

FUEL AND PURCHASED POWER

FPC, PEC and Fuels have entered into various long-term contracts for coal, oil and gas. Payments under these commitments were $2,097 million, $1,719 million and $1,414 million for 2004, 2003 and 2002, respectively.

Pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between PEC and the North Carolina Eastern Municipal Power Agency (Power Agency), PEC is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, the Harris Plant. 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 the Harris Plant, 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 $38 million. These contractual purchases totaled $39 million, $36 million and $36 million for 2004, 2003 and 2002, respectively. In 1987, the NCUC ordered PEC to reflect the recovery of the capacity portion of these costs on a levelized basis over the original 15-year buyback period, thereby deferring for future recovery the difference between such costs and amounts collected through rates. In 1988, the SCPSC ordered similar treatment, but with a 10-year levelization period. At December 31, 2004, all previously deferred costs have been expensed.

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 $43 million, representing capital-related capacity costs. Estimated annual payments for energy and capacity costs are approximately $72 million through 2009. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $63 million, $66 million and $59 million for 2004, 2003 and 2002, respectively.

PEC executed two long-term agreements for the purchase of power from Broad River LLC's (Broad River) facility. 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 300 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 $42 million, $37 million and $38 million in 2004, 2003 and 2002 respectively.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2015. Total purchases, for both energy and capacity, under these agreements amounted to $129 million, $124 million and $109 million for 2004, 2003 and 2002, respectively. Total capacity payments were $56 million, $55 million and $50 million for 2004, 2003 and 2002, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, at December 31, 2004 are $60 million, $63 million, $65 million, $66 million and $67 million for 2005 through 2009, respectively, and $244 million thereafter.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (qualifying facilities) with expiration dates ranging from 2005 to 2025. These purchased power contracts generally provide for capacity and energy payments. Energy payments for the PEF contracts are based on actual power taken under these contracts. Capacity payments are subject to the qualifying facilities (QFs) meeting certain contract performance obligations. PEF's total capacity purchases under these contracts amounted to $248 million, $244 million and $235 million for 2004, 2003 and 2002, respectively. Minimum expected future capacity payments under these contracts at December 31, 2004, are $271 million, $279 million, $289 million, $298 million and $263 million for 2005 through 2009, respectively, and $3.8 billion thereafter. PEC has various pay-for-performance contracts with QFs for approximately 400 MW of capacity expiring at various times through 2009. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $91 million in 2004, $113 million in 2003 and $145 million in 2002.

On December 2, 2004, PEF entered into precedent and related agreements with Southern Natural Gas Company (SNG), Florida Gas Transmission Company (FGT), and BG LNG Services, LLC for the supply of natural gas and associated firm pipeline transportation to augment PEF's gas supply needs for the period from May 1, 2007, to April 30, 2027. The total cost to PEF associated with the agreements is approximately $3.3 billion. The transactions are subject to several conditions precedent, which include obtaining the Florida Public Service Commission'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.

CONSTRUCTION OBLIGATIONS

The Company has purchase obligations related to various capital construction projects. Total payments under these contracts were $102 million, $158 million and $143 million for 2004, 2003 and 2002, respectively.

OTHER PURCHASE OBLIGATIONS

The Company has entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, a PVI parts and services contract, and a PEF service agreement related to the Hines Complex. Payments under these agreements were $69 million, $31 million and $420 million for 2004, 2003 and 2002, respectively.

On December 31, 2002, PEC and PVI entered into a contractual commitment to purchase at least $13 million and $4 million, respectively, of capital parts by December 31, 2010. During 2004 and 2003, no capital parts have been purchased under this contract.

B. Other Commitments

The Company has 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. The Company 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 $73 million and $94 million at December 31, 2004 and 2003, respectively, representing the minimum amounts due through 2007, discounted at 6.05%. At December 31, 2004 and 2003, 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. Actual amounts paid under these agreements were none in 2004, $2 million in 2003 and $51 million in 2002. Future expected minimum royalty payments are approximately $26 million for 2005 through 2007. The Company has the right in the related agreements and their amendments that allow the Company to escrow those payments if certain conditions in the agreements are met. The Company has exercised that right and retained 2004 and 2003 royalty payments of approximately $42 million and $48 million, respectively, pending the establishment of the necessary escrow accounts. Once established, those funds will be placed into escrow.

During 2004 Progress Energy made the first installment of $10 million for a contract dispute. The installments for 2005 and 2006, respectively, are $16 million and $17 million (See Note 20).

C. Leases

The Company leases 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. Rent expense under operating leases totaled $65 million, $60 million and $71 million for 2004, 2003 and 2002, respectively. Purchased power expense under agreements classified as operating leases were approximately $24 million in 2004 and $5 million in 2003.

Assets recorded under capital leases at December 31 consist of:

(in millions)	2004	2003
Buildings	$ 30	$ 30
Equipment and other	2	3
Less: Accumulated amortization	(11)	(10)
	$ 21	$ 23

Minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable leases at December 31, 2004, are:

(in millions)	Capital Leases	Operating Leases
2005	$ 4	$ 66
2006	4	55
2007	4	58
2008	4	58
2009	3	54
Thereafter	31	307
	$ 50	$ 598
Less amount representing imputed interest	(21)	
Present value of net minimum lease payments under capital leases	$ 29	

In 2003, the Company 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.

The Company, excluding PEC and PEF, is also a lessor of land, buildings and other types of properties it owns 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 2005 through 2009 are approximately $32 million, $22 million, $14 million, $9 million and $6 million, respectively, with $17 million receivable thereafter. Rents received under these operating leases totaled $63 million, $46 million and $53 million for 2004, 2003 and 2002, respectively.

PEC is the lessor of electric poles, streetlights and other facilities. Minimum rentals under noncancelable leases are $9 million for 2005 and none thereafter. Rents received totaled $32 million, $31 million and $28 million for 2004, 2003 and 2002, respectively.

PEF is the lessor of electric poles, streetlights and other facilities. Rents received are based on a fixed minimum rental where price varies by type of equipment and totaled $63 million, $56 million and $52 million for 2004, 2003 and 2002, respectively. Minimum rentals receivable (excluding streetlights) under noncancelable leases for 2005 is $5 million, for 2006 through 2009 $1 million, and $8 million thereafter. Streetlight rentals were $40 million, $38 million and $34 million for 2004, 2003 and 2002 respectively. Future streetlight rentals would approximate 2004 revenues.

D. Guarantees

To facilitate commercial transactions of the Company's subsidiaries, Progress Energy and certain wholly owned subsidiaries enter into agreements providing future financial or performance assurances to third parties (See Note 19).

At December 31, 2004, the Company had issued guarantees on behalf of third parties with an estimated maximum exposure of approximately $10 million. These guarantees support synthetic fuel operations. At December 31, 2004, management does not believe conditions are likely for significant performance under these agreements.

In connection with the sale of partnership interests in Colona (See Note 4B), Progress Fuels indemnified the buyers against any claims related to Colona resulting from violations of any environmental laws. Although the terms of the agreement provide for no limitation to the maximum potential future payments under the indemnification, the Company has estimated that the maximum total of such payments would not be material.

E. Claims and Uncertainties

OTHER CONTINGENCIES

1. Pursuant to the Nuclear Waste Policy Act of 1982, the predecessors to PEF and PEC entered into contracts with the U.S. Department of Energy (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.

DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, PEC and PEF 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 (SNF) by failing to accept SNF from various Progress Energy facilities on or before January 31, 1998. Damages due to DOE's breach will likely exceed $100 million. Approximately 60 cases involving the Government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims.

DOE and the PEC/PEF parties 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 SNF and high level waste (HLW) by which the Government was contractually obligated to accept contract holders' SNF and/or HLW, 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 that are currently scheduled to occur during 2005. Resolution of these issues in other cases could facilitate agreements by the parties in the PEC/PEF lawsuit, or at a minimum, inform the Court of decisions reached by other courts if they remain contested and require resolution in this case. The trial court has continued this stay until June 24, 2005.

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, Crystal River Unit No. 3 (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.

In July 2002, Congress passed an override resolution to Nevada's veto of DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nevada. In January 2003, the State of Nevada, Clark County, Nevada, and the City of Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged 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. EPA is currently reworking the standard but has not stated when the work will be complete. 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, DOE announced it would not submit the license application until mid-2005 or later. Also in November 2004, Congressional negotiators approved $577 million for fiscal year 2005 for the Yucca Mountain project, approximately $300 million less than requested by DOE but approximately the same as approved in 2004. The DOE continues to state it plans to begin operation of the repository at Yucca Mountain in 2010. PEC and PEF cannot predict the outcome of this matter.

2. In 2001, PEC entered into a contract to purchase coal from Dynegy Marketing and Trade (DMT). After DMT experienced financial difficulties, including credit ratings downgrades by certain credit reporting agencies, PEC requested credit enhancements in accordance with the terms of the coal purchase agreement in July 2002. When DMT did not offer credit enhancements, as required by a provision in the contract, PEC terminated the contract in July 2002.

PEC initiated a lawsuit seeking a declaratory judgment that the termination was lawful. DMT counterclaimed, stating the termination was a breach of contract and an unfair and deceptive trade practice. On March 23, 2004, the United States District Court for the Eastern District of North Carolina ruled that PEC was liable for breach of contract, but ruled against DMT on its unfair and deceptive trade practices claim. On April 6, 2004, the Court entered a judgment against PEC in the amount of approximately $10 million. The Court did not rule on DMT's request under the contract for pending legal costs.

On May 4, 2004, PEC authorized its outside counsel to file a notice of appeal of the April 6, 2004, judgment, and on May 7, 2004, the notice of appeal was filed with the United States Court of Appeals for the Fourth Circuit. On June 8, 2004, DMT filed a motion to dismiss the appeal on the ground that PEC's notice of appeal should have been filed on or before May 6, 2004. On June 16, 2004, PEC filed a motion with the trial court requesting an extension of the deadline for the filing of the notice of appeal. By order dated September 10, 2004, the trial court denied the extension request. On September 15, 2004, PEC filed a notice of appeal of the September 10, 2004, order, and by order dated September 29, 2004, the appellate court consolidated the first and second appeals. DMT's motion to dismiss the first appeal remains pending.

The consolidated appeal has been fully briefed, and the court of appeals has indicated that it will hear arguments, which tentatively have been scheduled for the week of May 23, 2005.

In the first quarter of 2004, PEC recorded a liability for the judgment of approximately $10 million and a regulatory asset for the probable recovery through its fuel adjustment clause. The Company cannot predict the outcome of this matter.

3. On February 1, 2002, the Company filed a complaint with the Surface Transportation Board (STB) challenging the rates charged by Norfolk Southern Railway Company (Norfolk Southern) for coal transportation to certain generating plants. In a decision dated December 23, 2003, the STB found that the rates were unreasonable, awarded reparations and prescribed maximum rates. Both parties petitioned the STB for reconsideration of the December 23, 2003 decision. On October 20, 2004, the STB reconsidered its December 23, 2003 decision and concluded that the rates charged by Norfolk Southern were not unreasonable. Because the Company paid the maximum rates prescribed by the STB in its December 23, 2003 decision for several months during 2004, which were less than the rates ultimately found to be reasonable, the STB ordered the Company to pay to Norfolk Southern the difference between the rate levels plus interest.

The Company subsequently filed a petition with the STB to phase in the new rates over a period of time, and filed a notice of appeal with the U.S. Court of Appeals for the D.C. Circuit. Pursuant to an order issued by the STB on January 6, 2005, the phasing proceeding will proceed on a schedule that appears likely to produce an STB decision before the end of 2005. On January 12, 2005, the STB filed a Motion to Dismiss the Company's appeal on the grounds that its October 20, 2004, order is not "final" until the Company's phasing application has been decided.

As of December 31, 2004, the Company has accrued a liability of $42 million, of which $23 million represents reparations previously remitted to PEC by Norfolk Southern that are now subject to refund. Of the remaining $19 million, $17 million has been recorded as deferred fuel cost on the Consolidated Balance Sheet, while the remaining $2 million attributable to wholesale customers has been charged to fuel used in electric generation on the Consolidated Statements of Income.

The Company cannot predict the outcome of this matter.

4. The Company, through its subsidiaries, is a majority owner in five entities and a minority owner in one entity that owns facilities that produce synthetic fuel as defined under the Internal Revenue Code (Code). The production and sale of the synthetic fuel from these facilities qualify for tax credits under Section 29 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. The amount of Section 29 credits that the Company is allowed to claim in any calendar year is limited by the amount of the Company's regular federal income tax liability. Synthetic fuel tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits. All entities have received PLRs from the IRS with respect to their synthetic fuel operations. However, these PLRs do not address the placed-in-service date determination. The PLRs do not limit the production on which synthetic fuel credits may be claimed. Total Section 29 credits generated to date (including those generated by FPC prior to its acquisition by the Company) are approximately $1.5 billion, of which $713 million has been used to offset regular federal income tax liability and $745 million is being carried forward as deferred alternative minimum tax credits. Also, $7 million has not been recognized due to the decrease in tax liability resulting from expenses incurred for the 2004 hurricane damage. The current Section 29 tax credit program expires at the end of 2007.

IMPACT OF HURRICANES

For the year ended December 31, 2004, the Company's synthetic fuel facilities sold 8.3 million tons of synthetic fuel and the Company recorded $215 million of Section 29 tax credits. The amount of synthetic fuel sold and tax credits recorded in 2004 was impacted by hurricane costs that reduced the Company's projected 2004 regular tax liability.

For the nine months ended September 30, 2004, the Company's synthetic fuel facilities sold 7.7 million tons of synthetic fuel, which generated an estimated $204 million of Section 29 tax credits. Due to the anticipated decrease in the Company's tax liability as a result of expenses incurred for the 2004 hurricane damage, the Company estimated that it would be able to use in 2004, or carry forward to future years, only $125 million of these Section 29 tax credits at September 30, 2004. As a result, the Company recorded a charge of $79 million related to Section 29 tax credits at September 30, 2004.

On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from customers over a two-year period. Based on a reasonable expectation at December 31, 2004, that the FPSC will grant the requested recovery of the storm costs, the Company's loss from the casualty is less than originally anticipated. As of December 31, 2004, the Company estimates that it will be able to use in 2004, or carry forward to future years, $215 million of these Section 29 tax credits. Therefore, the Company recorded tax credits of $90 million for the quarter ended December 31, 2004, which the Company now anticipates can be used. For the year ended December 31, 2004, the Company's synthetic fuel facilities sold 8.3 million tons of synthetic fuel, which generated an estimated $222 million of Section 29 tax credits. As of December 31, 2004, the Company anticipates that approximately $7 million of tax credits related to synthetic fuel sold during the year could not be used and have not been recognized.

The Company believes its right to recover storm costs is well established; however, the Company cannot predict the timing or outcome of this matter. If the FPSC should deny PEF's petition for the recovery of storm costs in 2005, there could be a material impact on the amount of 2005 synthetic fuels production and results of operations.

IRS PROCEEDINGS

In September 2002, all of Progress Energy's majority-owned synthetic fuel entities were accepted into the IRS's Pre-Filing Agreement (PFA) program. The PFA program allows taxpayers to voluntarily accelerate the IRS exam process in order to seek resolution of specific issues.

In February 2004, subsidiaries of the Company finalized execution of the Colona Closing Agreement with the IRS concerning their Colona synthetic fuel facilities. The Colona Closing Agreement provided that the Colona facilities were placed in service before July 1, 1998, which is one of the qualification requirements for tax credits under Section 29. The Colona Closing Agreement further provides that the fuel produced by the Colona facilities in 2001 is a "qualified fuel" for purposes of the Section 29 tax credits. This action concluded the PFA program with respect to Colona.

In July 2004, Progress Energy was notified that the IRS field auditors anticipated taking an adverse position regarding the placed-in-service date of the Company's four Earthco synthetic fuel facilities. Due to the auditors' position, the IRS decided to exercise its right to withdraw from the PFA program with Progress Energy. With the IRS's withdrawal from the PFA program, the review of Progress Energy's Earthco facilities is back on the normal procedural audit path of the Company's tax returns. Through December 31, 2004, the Company, on a consolidated basis, has used or carried forward approximately $1.0 billion of tax credits generated by Earthco facilities. If these credits were disallowed, the Company's one-time exposure for cash tax payments would be $294 million (excluding interest), and earnings and equity would be reduced by approximately $1.0 billion, excluding interest. Progress Energy's amended $1.13 billion credit facility includes a covenant that limits the maximum debt-to-total capital ratio to 68%. This ratio includes other forms of indebtedness such as guarantees issued by PGN, letters of credit and capital leases. As of December 31, 2004, the Company's debt-to-total capital ratio was 60.7% based on the credit agreement definition for this ratio. The impact on this ratio of reversing approximately $1.0 billion of tax credits and paying $294 million for taxes would be to increase the ratio to 65.7%.

On October 29, 2004, Progress Energy received the IRS field auditors' report concluding that the Earthco facilities had not been placed in service before July 1, 1998, and that the tax credits generated by those facilities should be disallowed. The Company disagrees with the field audit team's factual findings and believes that the Earthco facilities were placed in service before July 1, 1998. The Company also believes that the report applies an inappropriate legal standard concerning what constitutes "placed in service." The Company intends to contest the field auditors' findings and their proposed disallowance of the tax credits.

Because of the disagreement between the Company and the field auditors as to the proper legal standard to apply, the Company believes that it is appropriate and helpful to have this issue reviewed by the National Office of the IRS, just as the National Office reviewed the issues involving chemical change. Therefore, the Company is asking the National Office to clarify the legal standard and has initiated this process with the National Office. The Company believes that the appeals process, including proceedings before the National Office, could take up to two years to complete; however, it cannot control the actual timing of resolution and cannot predict the outcome of this matter.

In management's opinion, the Company is complying with all the necessary requirements to be allowed such credits under Section 29, and, although it cannot provide certainty, it believes that it will prevail in these matters. Accordingly, while the Company adjusted its synthetic fuel production for 2004 in response to the effects of expenses incurred due to the hurricane damage and its impact on 2004 tax liability, it has no current plans to alter its synthetic fuel production schedule for future years as a result of the IRS field auditors' report. However, should the Company fail to prevail in these matters, there could be material liability for previously taken Section 29 tax credits, with a material adverse impact on earnings and cash flows.

PROPOSED ACCOUNTING RULES FOR UNCERTAIN TAX POSITIONS

In July 2004, the FASB stated that it plans to issue 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 FASB has indicated that the interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the financial statements. The exposure draft is expected to be issued in the first quarter of 2005. The Company cannot predict what actions the FASB will take or how any such actions might ultimately affect the Company's financial position or results of operations, but such changes could have a material impact on the Company's evaluation and recognition of Section 29 tax credits.

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 the Company's synthetic fuel operations. Progress Energy is providing information in connection with this investigation. The Company cannot predict the outcome of this matter.

SALE OF PARTNERSHIP INTEREST

In June 2004, the Company, through its subsidiary, Progress Fuels, sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, 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 Company's book value of the interests sold totaled approximately $5 million. The company received total gross proceeds of $10 million in 2004. Based on projected production and tax credit levels, the Company anticipates receiving approximately $24 million in 2005, approximately $31 million in 2006, approximately $32 million in 2007 and approximately $8 million through the second quarter of 2008. 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.

IMPACT OF CRUDE OIL PRICES

Although the Internal Revenue Code Section 29 tax credit program is expected to continue through 2007, recent unprecedented and unanticipated increases in the price of oil could limit the amount of those credits or eliminate them altogether for one or more of the years following 2004. 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 value (the "Threshold Price"), the amount of Section 29 tax credits are reduced for that year. Also, if the Annual Average Price increases high enough (the "Phase Out Price"), the Section 29 tax credits are eliminated for that year. For 2003, the Threshold Price was $50.14 per barrel and the Phase Out Price was $62.94 per barrel. The Threshold Price and the Phase Out Price are adjusted annually for inflation.

If the Annual Average Price falls between the Threshold Price and the Phase Out Price for a year, the amount by which Section 29 tax credits are reduced will depend on where the Average Annual Price falls in that continuum. For example, for 2003, if the Annual Average Price had been $56.54 per barrel, there would have been a 50% 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 its calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2003 was published in April 2004.

Although the official notice for 2004 is not expected to be published until April 2005, the Company does not believe that the Annual Average Price for 2004 will reach the Threshold Price for 2004. Consequently, the Company does not expect the amount of its 2004 Section 29 tax credits to be adversely affected by oil prices.

The Company cannot predict with any certainty the Annual Average Price for 2005 or beyond. Therefore, it cannot predict whether the price of oil will have a material effect on its synthetic fuel business after 2004. However, if during 2005 through 2007, oil prices remain at historically high levels or increase, the Company's synthetic fuel business may be adversely affected for those years, and, depending on the magnitude of such increases in oil prices, the adverse affect for those years could be material and could have an impact on the Company's synthetic fuel results of operations and production plans.

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

24. SUBSEQUENT EVENTS

Sale of Progress Rail

On February 18, 2005, the Company announced it has entered into a definitive agreement to sell Progress Rail to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Gross cash proceeds from the transaction will be $405 million, subject to working capital adjustments. The sale is expected to close by mid-2005, and is subject to various closing conditions customary to such transactions. Proceeds from the sale are expected to be used to reduce debt. The Company expects to report Progress Rail as a discontinued operation in the first quarter of 2005. The carrying amounts for the assets and liabilities of the discontinued operations disposal group included in the Consolidated Balance Sheets as of December 31, are as follows:

(in millions)	2004	2003
Total current assets	$ 378	$ 373
Total property, plant & equipment (net)	173	151
Total other assets	40	77
Total current liabilities	156	114
Total long-term liabilities	3	3
Total capitalization	432	484

Cost Management Initiative

On February 28, 2005, as part of a previously announced cost management initiative, the executive officers of the Company approved a workforce restructuring. The restructuring will result in a reduction of approximately 450 positions and is expected to be completed in September 2005. The cost management initiative is designed to permanently reduce by $75-100 million the projected growth in the Company's annual operation and maintenance expenses by the end of 2007. In addition to the workforce restructuring, the cost management initiative includes a voluntary enhanced retirement program.

In connection with the cost management initiative, the Company expects to incur one-time pre-tax charges of approximately $130 million. Approximately $30 million of that amount relates to payments for severance benefits, and will be recognized in the first quarter of 2005 and paid over time. The remaining approximately $100 million will be recognized in the second quarter of 2005 and relates primarily to postretirement benefits that will be paid over time to those eligible employees who elect to participate in the voluntary enhanced retirement program. Approximately 3,500 of the Company's 15,700 employees are eligible to participate in the voluntary enhanced retirement program. The total cost management initiative charges could change significantly depending upon how many eligible employees elect early retirement under the voluntary enhanced retirement program and the salary, service years and age of such employees.

25. CONSOLIDATED QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data is as follows:

(in millions except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2004				
Operating revenues	**$ 2,245**	**$ 2,408**	**$ 2,761**	**$ 2,358**
Operating income	**296**	**305**	**584**	**291**
Income from continuing operations before cumulative effect of changes in accounting principles	**108**	**153**	**303**	**189**
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	**0.45**	**0.63**	**1.25**	**0.78**
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	**0.45**	**0.63**	**1.24**	**0.78**
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**

Year ended December 31, 2003				
Operating revenues	$ 2,187	$ 2,050	$ 2,457	$ 2,047
Operating income	357	274	478	248
Income from continuing operations before cumulative effect of changes in accounting principles	207	154	337	113
Net income	219	157	318	88
Common stock data:				
Basic earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	0.89	0.65	1.41	0.47
Net income	0.94	0.66	1.33	0.37
Diluted earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	0.89	0.65	1.39	0.47
Net income	0.94	0.66	1.31	0.37
Dividends declared per common share	0.560	0.560	0.560	0.575
Market price per share – High	46.10	48.00	45.15	46.00
– Low	37.45	38.99	39.60	41.60

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. Fourth quarter 2004 includes a $31 million after-tax gain on sale of natural gas assets (See Note 4A) and the recording of $90 million of Section 29 tax credit (See Note 23E). Third quarter 2004 includes the reversal of $79 million of Section 29 tax credits (See Note 23E). Second quarter 2004 includes the settlement of a civil proceeding related to SRS of $43 million ($29 million after-tax) (See Note 20). Fourth quarter 2003 includes impairment charges related to Kentucky May and certain Affordable Housing investments of $38 million ($24 million after-tax) (See Note 10). Fourth quarter 2003 includes the impact of a cumulative effect for DIG Issue 20 of $38 million ($23 million after-tax) (See Note 18).

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.:

We have audited the accompanying consolidated balance sheets of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., and its subsidiaries (PEC) at December 31, 2004 and 2003, and the related consolidated statements of income, retained earnings, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the PEC's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PEC December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 1D and 13A to the consolidated financial statements, in 2003, PEC adopted Statement of Financial Accounting Standards No. 143 and Derivative Implementation Group Issue C20.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 7, 2005

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED STATEMENTS of INCOME

(in millions) Years ended December 31	2004	2003	2002
Operating Revenues			
Electric	$ 3,628	$ 3,589	$ 3,539
Diversified business	1	11	15
Total Operating Revenues	3,629	3,600	3,554
Operating Expenses			
Fuel used in electric generation	836	825	752
Purchased power	301	296	347
Operation and maintenance	871	782	802
Depreciation and amortization	570	562	524
Taxes other than on income	173	162	158
Diversified business	1	4	15
Impairment of diversified business long-lived assets	–	–	101
Total Operating Expenses	2,752	2,631	2,699
Operating Income	877	969	855
Other Income (Expense)			
Interest income	4	6	7
Impairment of investments	–	(21)	(25)
Other, net	11	(11)	13
Total Other Income (Expense)	15	(26)	(5)
Interest Charges			
Interest charges	195	198	217
Allowance for borrowed funds used during construction	(3)	(1)	(5)
Total Interest Charges, Net	192	197	212
Income before Income Tax and Cumulative Effect of Change in Accounting Principles	700	746	638
Income Tax Expense	239	241	207
Income before Cumulative Effect of Change in Accounting Principles	461	505	431
Cumulative Effect of Change in Accounting Principles, Net of Tax	–	(23)	–
Net Income	461	482	431
Preferred Stock Dividend Requirement	3	3	3
Earnings for Common Stock	$ 458	$ 479	$ 428

See Notes to Consolidated Financial Statements.

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2004	2003
ASSETS		
Utility Plant		
Utility plant in service	$ 13,521	$ 13,331
Accumulated depreciation	(5,806)	(5,307)
Utility plant in service, net	7,715	8,024
Held for future use	5	5
Construction work in progress	379	267
Nuclear fuel, net of amortization	186	159
Total Utility Plant, Net	8,285	8,455
Current Assets		
Cash and cash equivalents	18	12
Short-term investments	82	226
Receivables	397	410
Receivables from affiliated companies	20	27
Inventory	390	387
Deferred fuel cost	140	66
Income taxes receivable	59	37
Prepayments and other current assets	76	63
Total Current Assets	1,182	1,228
Deferred Debits and Other Assets		
Regulatory assets	473	463
Nuclear decommissioning trust funds	581	505
Miscellaneous other property and investments	158	169
Other assets and deferred debits	108	118
Total Deferred Debits and Other Assets	1,320	1,255
Total Assets	$ 10,787	$ 10,938
CAPITALIZATION AND LIABILITIES		
Common Stock Equity		
Common stock without par value, authorized 200 million shares, 160 million shares issued and outstanding at December 31	$ 1,975	$ 1,953
Unearned ESOP common stock	(76)	(89)
Accumulated other comprehensive loss	(114)	(7)
Retained earnings	1,287	1,380
Total Common Stock Equity	3,072	3,237
Preferred Stock – Not Subject to Mandatory Redemption	59	59
Long-Term Debt, Net	2,750	3,086
Total Capitalization	5,881	6,382
Current Liabilities		
Current portion of long-term debt	300	300
Accounts payable	254	188
Payables to affiliated companies	83	136
Notes payable to affiliated companies	116	25
Interest accrued	77	80
Short-term obligations	221	4
Customer deposits	45	40
Other current liabilities	179	133
Total Current Liabilities	1,275	906
Deferred Credits and Other Liabilities		
Noncurrent income tax liabilities	991	1,057
Accumulated deferred investment tax credits	140	148
Regulatory liabilities	1,052	1,149
Asset retirement obligations	924	932
Accrued pension and other benefits	383	207
Other liabilities and deferred credits	141	157
Total Deferred Credits and Other Liabilities	3,631	3,650
Commitments and Contingencies (Notes 17 and 18)		
Total Capitalization and Liabilities	$ 10,787	$ 10,938

See Notes to Consolidated Financial Statements.

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions) Years ended December 31	2004	2003	2002
Operating Activities			
Net income	$ 461	$ 482	$ 431
Adjustments to reconcile net income to net cash provided by operating activities:			
Impairment of long-lived assets and investments	–	21	126
Depreciation and amortization	658	660	631
Cumulative effect of change in accounting principles	–	23	–
Deferred income taxes	(19)	(69)	(82)
Investment tax credit	(7)	(10)	(12)
Deferred fuel credit	(56)	33	(15)
Cash provided (used) by changes in operating assets and liabilities:			
Receivables	(4)	10	(13)
Receivables from affiliated companies	7	20	(8)
Inventory	(18)	(21)	5
Prepayments and other current assets	13	21	(15)
Accounts payable	35	(56)	39
Accounts payable to affiliated companies	(53)	24	(19)
Other current liabilities	9	57	(2)
Other	50	38	32
Net Cash Provided by Operating Activities	1,076	1,233	1,098
Investing Activities			
Gross property additions	(519)	(445)	(619)
Proceeds from sale of subsidiaries and other investments	25	28	244
Diversified business property additions and acquisitions	–	(1)	(12)
Nuclear fuel additions	(101)	(66)	(81)
Net contributions to nuclear decommissioning trust	(31)	(31)	(31)
Purchases of short-term investments	(2,108)	(2,813)	(2,962)
Proceeds from sales of short-term investments	2,252	2,587	2,962
Other investing activities	(3)	(1)	(17)
Net Cash Used in Investing Activities	(485)	(742)	(516)
Financing Activities			
Proceeds from issuance of long-term debt	–	588	542
Net increase (decrease) in short-term obligations	217	(437)	177
Net change in intercompany notes	91	74	(97)
Retirement of long-term debt	(339)	(276)	(807)
Dividends paid to parent	(551)	(443)	(397)
Dividends paid on preferred stock	(3)	(3)	(3)
Net Cash Used in Financing Activities	(585)	(497)	(585)
Net Increase (Decrease) in Cash and Cash Equivalents	6	(6)	(3)
Cash and Cash Equivalents at Beginning of Year	12	18	21
Cash and Cash Equivalents at End of Year	$ 18	$ 12	$ 18
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year – interest (net of amount capitalized)	$ 185	$ 180	$ 203
income taxes (net of refunds)	$ 286	$ 296	$ 319

See Notes to Consolidated Financial Statements.

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED STATEMENTS of RETAINED EARNINGS

(in millions) Years ended December 31	2004	2003	2002
Retained Earnings at Beginning of Year	**$ 1,380**	$ 1,344	$ 1,313
Net income	**461**	482	431
Preferred stock dividends at stated rates	**(3)**	(3)	(3)
Common stock dividends	**(551)**	(443)	(397)
Retained Earnings at End of Year	**$ 1,287**	$ 1,380	$ 1,344

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	2004	2003	2002
Net Income	**$ 461**	$ 482	$ 431
Other Comprehensive Income			
Changes in net unrealized losses on cash flow hedges (net of tax (expense) benefit of $1, ($1) and $9, respectively)	**(1)**	3	(14)
Reclassification adjustment for amounts included in net income (net of tax benefit of $0, $0 and $8, respectively)	**–**	1	11
Minimum pension liability adjustment (net of tax (expense) benefit of $68, ($47) and $47, respectively)	**(106)**	72	(73)
Other Comprehensive Income	**$ (107)**	$ 76	$ (76)
Comprehensive Income	**$ 354**	$ 558	$ 355

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

Carolina Power & Light Company (CP&L) is a public service corporation primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Effective January 1, 2003, CP&L began doing business under the assumed name Progress Energy Carolinas, Inc. (PEC). The legal name has not changed and there was no restructuring of any kind related to the name change. Through its wholly owned subsidiaries, PEC is involved in several nonregulated business activities, the most significant of which was Caronet, Inc. (Caronet), its telecommunications operation. PEC is a wholly owned subsidiary of Progress Energy, Inc. (the Company or Progress Energy). The Company is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). Both the Company and its subsidiaries are subject to the regulatory provisions of PUHCA.

In December 2003, Progress Telecommunications Corporation (PTC) and Caronet, both indirectly 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. Subsequently, the stock of Caronet was sold to an affiliate of Odyssey for $2 million in cash, and Caronet became an indirect wholly owned subsidiary of Odyssey. No gain or loss was recognized on this transaction.

B. Basis of Presentation

The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the activities of PEC and its majority-owned subsidiaries. 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," 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.

The consolidated financial statements of PEC and its subsidiaries include the majority owned and controlled subsidiaries. Noncontrolling interests in the subsidiaries are included in other liabilities and deferred credits in the Consolidated Balance Sheets. Income or losses from these interests are included in other income 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 PEC does not have control, but has the ability to exercise influence over operating and financial policies (generally 20% – 50% 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 16). These equity method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, PEC has equity method investments of approximately $15 million and $24 million, respectively.

Certain investments in debt and equity securities that have readily determinable market values, and for which PEC does not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." These investments include investments held in trust funds, pursuant to United States Nuclear Regulatory Commission (NRC) requirements, to fund certain costs of decommissioning nuclear plants. The fair value of these trust funds was $581 million and $505 million at December 31, 2004 and 2003, respectively. PEC also 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 which allow for the redemption of the investment at its face amount plus earned income. As PEC intends to sell these instruments generally within 30 days from the balance sheet date, they are classified as current assets. At December 31, 2004 and 2003, the fair value of these investments was $82 million and $226 million, respectively. Other investments in debt and equity securities are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, the fair value of these other investments was $3 million and $2 million, respectively.

Other investments are stated principally at cost. These cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, PEC has approximately $1 million and $1 million, respectively, of cost method investments.

Certain amounts for 2003 and 2002 have been reclassified to conform to the 2004 presentation. Reclassifications include the reclassification of instruments used in PEC's cash management program from cash and cash equivalents to short-term investments of $226 million at December 31, 2003 in the Consolidated Balance Sheets. In the Consolidated Statements of Cash Flow for each of the three years in the period ended December 31, 2004, total cash balances and total cash flows used in investing activities were revised to reflect the reclassification of these instruments from cash and cash equivalents to short-term investments.

C. Consolidation of Variable Interest Entities

PEC consolidates all voting interest entities in which it owns a majority voting interest and all variable interest entities for which it is the primary beneficiary in accordance with FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51" (FIN No. 46R). PEC is the primary beneficiary of and consolidates two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Internal Revenue Code. As of December 31, 2004, the total assets of the two entities were $37 million, the majority of which are collateral for the entities' obligations and are included in other current assets and miscellaneous other property and investments in the Consolidated Balance Sheet.

PEC is the primary beneficiary of a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. PEC has requested but has not received all the necessary information to determine the primary beneficiary of the limited partnership's underlying 17 partnership investments, and 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 has variable interests in two power plants resulting from long-term power purchase contracts. PEC has requested the necessary information to determine if the counterparties are variable interest entities or to identify the primary beneficiaries. Both entities declined to provide PEC with the necessary financial information, and PEC has applied the information scope exception in FIN No. 46R, paragraph 4(g). PEC's only significant exposure to variability from these contracts results from fluctuations in the market price of fuel used by the two entities' plants to produce the power purchased by PEC. PEC is able to recover these fuel costs under its fuel clause. Total purchases from these counterparties were approximately $58 million, $53 million and $53 million in 2004, 2003 and 2002, respectively. PEC will continue its efforts to obtain the necessary information to fully apply FIN No. 46R to these contracts. The combined generation capacity of the two entities' power plants is approximately 880 MW. PEC believes that if it is determined to be the primary beneficiary of these two entities, the effect of consolidating the entities would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from these two counterparties, 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 partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. The aggregate maximum loss exposure at December 31, 2004, that PEC could be required to record in its income statement as a result of these arrangements totals approximately $23 million. 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.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

In preparing consolidated financial statements that conform with 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

PEC recognizes electric utility revenue 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. Revenues related to Caronet for the design and construction of wireless infrastructure were recognized upon completion of services for each completed phase of design and construction.

FUEL COST DEFERRALS

Fuel expense includes fuel costs or recoveries that are deferred through fuel clauses established by PEC's regulators. These clauses allow PEC 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

PEC collects from customers certain excise taxes levied by the state or local government upon the customer. PEC accounts for excise taxes on a gross basis. For the years ended December 31, 2004, 2003 and 2002, gross receipts tax and other excise taxes of approximately $89 million, $81 million and $80 million, respectively, are included in electric revenue and taxes other than on income on the Consolidated Statements of Income.

INCOME TAXES

Progress Energy and its affiliates file a consolidated federal income tax return. The consolidated income tax of Progress Energy is allocated to PEC 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. Progress Energy tax benefits not related to acquisition interest expense are allocated to profitable subsidiaries, beginning in 2002, in accordance with a PUHCA order. Except for the allocation of this Progress Energy tax benefit, income taxes are provided as if PEC filed a separate return.

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 (See Note 11).

STOCK-BASED COMPENSATION

PEC participates in the stock option programs offered by Progress Energy (See Note 8B). PEC measures compensation expense for stock options as the difference between the market price of Progress Energy's common stock and the exercise price of the option at the grant date. The exercise price at which options are granted by Progress Energy equals the market price at the grant date, and, accordingly, no compensation expense has been recognized for stock option grants. For purposes of the pro forma disclosures required by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an Amendment of FASB Statement No. 123" (SFAS No. 148), the estimated fair value of Progress Energy's stock options is amortized to expense over the options' vesting period. The following table illustrates the effect on net income if the fair value method had been applied to all outstanding and unvested awards in each period.

(in millions)	2004	2003	2002
Net income, as reported	$ 461	$ 482	$ 431
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	7	6	5
Pro forma net income	$ 454	$ 476	$ 426

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. PEC capitalizes 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. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal, disposal or decommissioning costs that do not represent ARO's under SFAS No. 143 "Accounting for Asset Retirement Obligations," (SFAS No. 143) are charged to regulatory liabilities.

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, PEC adopted the guidance in SFAS No. 143 to account for legal obligations associated with the retirement of certain tangible long-lived assets. The present value of retirement costs for which PEC has 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.

The adoption of this statement had no impact on the income of PEC, as the effects were offset by the establishment of a regulatory asset pursuant to SFAS No. 71 and related orders by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (SCPSC) (See Note 6A). The NCUC and SCPSC also issued an order to authorize deferral of all prospective effects related to SFAS No. 143 as a regulatory asset or liability. Therefore, SFAS No. 143 has no impact on the income of PEC.

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 4A). Pursuant to their rate-setting authority, the NCUC and SCPSC can also grant approval to accelerate or reduce depreciation and amortization of utility assets.

Amortization of nuclear fuel costs is computed primarily on the units-of-production method. In PEC's retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC and the SCPSC 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 Federal Energy Regulatory Commission (FERC).

CASH AND CASH EQUIVALENTS

PEC considers 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

PEC accounts for inventory using the average-cost method. Inventories are valued at the lower cost or market.

REGULATORY ASSETS AND LIABILITIES

PEC's regulated 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, PEC records 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 6A).

DIVERSIFIED BUSINESS PROPERTY

Diversified business property is stated at cost less accumulated depreciation. If an impairment loss 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. Depreciation is computed on a straight-line basis using the estimated useful lives disclosed in Note 4B.

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

Long-term debt premiums, discounts and issuance expenses for the utility are amortized over the life of the related debt using the straight-line method. Any expenses or call premiums associated with the reacquisition of debt obligations by the utility are amortized over the remaining life of the original debt using the straight-line method consistent with ratemaking treatment (See Note 6A).

DERIVATIVES

Effective January 1, 2001, PEC adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138 and 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. PEC generally designates 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, PEC 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 13 for the effect of the interpretation and additional information regarding risk management activities and derivative transactions.

ENVIRONMENTAL

As discussed in Note 17, PEC accrues environmental remediation liabilities when the criteria for SFAS No. 5, "Accounting for Contingencies," has 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. Environmental expenditures that have future economic benefits are capitalized in accordance with PEC's asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

PEC reviews 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, 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, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. The accounting for impairment of long-lived assets is based on SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

PEC reviews its investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. PEC considers 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 PEC determines that an other-than-temporary decline exists in the value of its investments, it is PEC's policy to write-down these investments to fair value. See Note 7 for a discussion of impairment evaluations performed and charges taken.

SUBSIDIARY STOCK TRANSACTIONS

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

2. NEW ACCOUNTING STANDARDS

FASB STAFF POSITION 106-2, "ACCOUNTING AND DISCLOSURE REQUIREMENTS RELATED TO THE MEDICARE PRESCRIPTION DRUG IMPROVEMENT AND MODERNIZATION ACT OF 2003"

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law. In accordance with guidance issued by the FASB in FASB Staff Position 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003" (FASB Staff Position 106-1), PEC elected to defer accounting for the effects of the Medicare Act due to uncertainties regarding the effects of the implementation of the Medicare Act and the accounting for certain provisions of the Medicare Act. In May 2004, the FASB issued definitive accounting guidance for the Medicare Act in FASB Staff Position 106-2, which was effective for PEC in the third quarter of 2004. FASB Staff Position 106-2 results in the recognition of lower other postretirement employee benefit (OPEB) costs to reflect prescription drug-related federal subsidies to be received under the Medicare Act. As a result of the Medicare Act, PEC's accumulated postretirement benefit obligation as of January 1, 2004, was reduced by approximately $42 million, and PEC's 2004 net periodic cost was reduced by approximately $7 million.

STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 123 (REVISED 2004), "SHARE-BASED PAYMENT" (SFAS NO. 123R)

In December 2004, the FASB issued SFAS No. 123R, which revises SFAS No. 123, "Accounting for Stock-Based Compensation" and supersedes Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." The key requirement of SFAS No. 123R is that the cost of share-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. Previously, entities could elect to continue accounting for such awards at their grant date intrinsic value under APB Opinion No. 25, and PEC made that election. The intrinsic value method resulted in PEC recording no compensation expense for stock options granted to employees (See Note 1D).

SFAS No. 123R will be effective for PEC on July 1, 2005. PEC intends to implement the standard using the required modified prospective method. Under that method, PEC will record compensation expense under SFAS No. 123R for all awards it grants after July 1, 2005, and it will record compensation expense (as previous awards continue to vest) for the unvested portion of previously granted awards that remain outstanding at July 1, 2005. In 2004, Progress Energy made the decision to cease granting stock options and intends to replace that compensation program with other programs. Therefore, the amount of stock option expense expected to be recorded in 2005 is below the amount that would have been recorded if the stock option program had continued. PEC expects to record approximately $1 million of pre-tax expense for stock options in 2005.

3. HURRICANE RELATED COSTS

Hurricanes Charley and Ivan struck significant portions of PEC's service territories during the third quarter of 2004. PEC incurred restoration costs of $13 million, of which $12 million was charged to operation and maintenance expense and $1 million was charged to capital expenditures. PEC does not have an ongoing regulatory mechanism to recover storm costs; and therefore, hurricane restoration costs recorded in the third quarter of 2004 were charged to operations and maintenance expenses or capital expenditures based on the nature of the work performed. In connection with other storms, PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over a five-year period. PEC did not seek deferral of 2004 hurricane restoration costs (See Note 6B).

4. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

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

(in millions)	2004	2003
Production plant (7-33 years)	$ 7,954	$ 8,024
Transmission plant (30-75 years)	1,212	1,155
Distribution plant (12-50 years)	3,701	3,538
General plant and other (8-75 years)	654	614
Utility plant in service	$ 13,521	$ 13,331

Generally, electric utility plant, other than nuclear fuel, is pledged as collateral for the first mortgage bonds of PEC (See Note 9).

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 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 7.2% in 2004, 4.0% in 2003 and 6.2% in 2002.

Depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.1% in 2004, and 2.7% in 2003 and 2002, respectively. The depreciation provisions related to utility plant were $275 million, $345 million and $326 million in 2004, 2003 and 2002, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, asset retirement obligations (ARO) accretion, cost of removal provisions (See Note 4D), regulatory approved expenses (See Note 6) and clean air amortization (See Note 6B).

During 2004, PEC met the requirements of both the NCUC and the SCPSC for the implementation of a depreciation study which 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 new depreciation rates were effective January 1, 2004.

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, 2004, 2003 and 2002 were $106 million, $112 million and $109 million, respectively, and are included in fuel used for electric generation.

B. Diversified Business Property

Gross diversified business property was $7 million at December 31, 2004 and 2003, respectively. These amounts consist primarily of buildings and equipment that are being depreciated over periods ranging from 31 to 65 years. Accumulated depreciation was $2 million and $1 million at December 31, 2004 and 2003, respectively. Diversified business depreciation expense was $1 million in 2004 and 2003, and $4 million in 2002. Net diversified business property is included in miscellaneous other property and investments on the Consolidated Balance Sheets.

C. Joint Ownership of Generating Facilities

PEC holds ownership interests in certain jointly owned generating facilities. PEC is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. PEC also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. PEC's share of expenses for the jointly owned facilities is included in the appropriate expense category. PEC's ownership interest in the jointly owned generating facilities is listed below with related information at December 31 ($ in millions):

2004 **Facility**	**Company Ownership Interest**	**Plant Investment**	**Accumulated Depreciation**	**Construction Work in Progress**
Mayo Plant	**83.83%**	**$ 516**	**$ 249**	**$ 1**
Harris Plant	**83.83%**	**3,185**	**1,387**	**13**
Brunswick Plant	**81.67%**	**1,624**	**888**	**28**
Roxboro Unit No. 4	**87.06%**	**323**	**147**	**1**

2003 Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work In Progress
Mayo Plant	83.83%	$ 464	$ 242	$ 50
Harris Plant	83.83%	3,248	1,424	7
Brunswick Plant	81.67%	1,611	885	21
Roxboro Unit No. 4	87.06%	323	139	1

In the tables above, plant investment and accumulated depreciation are not reduced by the regulatory disallowances related to the Shearon Harris Nuclear Plant (Harris Plant).

D. Asset Retirement Obligations

At December 31, 2004 and 2003, the asset retirement costs related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $46 million and $113 million, respectively. Funds set aside in PEC's nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $580 million and $505 million at December 31, 2004 and 2003, respectively. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 6A).

Decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million in each of 2004, 2003 and 2002. Management believes that the decommissioning costs that have been and will be recovered through rates will be sufficient to provide for the costs of decommissioning. PEC's expense recognized for the disposal or removal of utility assets that are not SFAS No. 143 asset removal obligations, which are included in depreciation and amortization expense, were $83 million, $86 million and $81 million in 2004, 2003 and 2002, respectively.

PEC recognizes removal, nonirradiated decommissioning and dismantlement costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 6A). At December 31, 2004, such costs consist of removal costs of $601 million and removal costs for nonirradiated areas at nuclear facilities of $70 million. At December 31, 2003, such costs consist of removal costs of $901 million and removal costs for nonirradiated areas at nuclear facilities of $67 million. During 2004, PEC reduced its estimated removal costs to take into account the estimates used in the depreciation studies implemented during 2004 (See Note 4A). This resulted in a downward revision in the PEC estimated removal costs and equal increase in accumulated depreciation of approximately $345 million.

PEC re-measured its ARO for the nuclear decommissioning of irradiated plants to take into account updated site-specific decommissioning cost studies, which are required by the NCUC every five years. The ARO for nuclear decommissioning was reduced by $63 million to $924 million.

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 estimates, in 2004 dollars, are $294 million for Robinson Unit No. 2, $290 million for Brunswick Unit No. 1, $313 million for Brunswick Unit No. 2 and $359 million for the Harris Plant. 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 the Brunswick and Harris nuclear generating facilities. NRC operating licenses held by PEC currently expire in December 2014 and September 2016 for Brunswick Units 2 and 1, respectively. An application to extend these licenses 20 years was submitted in October 2004. The NRC operating license held by PEC for the Shearon Harris Nuclear Plant (Harris Plant) 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 has renewed the operating license for PEC's Robinson Nuclear Plant (Robinson) for an additional 20 years through July 2030.

PEC has identified but not recognized AROs related to electric transmission and distribution assets as the result of easements over property not owned by PEC. 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 PEC intends to utilize these properties indefinitely. In the event PEC decides to abandon or cease the use of a particular easement, an ARO would be recorded at that time.

The following table shows the changes to the asset retirement obligations:

(in millions)	
Asset retirement obligations as of January 1, 2003	$ 880
Accretion expense	52
Asset retirement obligations as of December 31, 2003	932
Accretion expense	55
Deductions	(63)
Asset retirement obligations as of December 31, 2004	$ 924

E. Insurance

PEC is a member 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, PEC is insured for $500 million at each of its nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $2.0 billion on the Brunswick and Harris Plants and $1.1 billion on the Robinson 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. PEC is insured there under, following a 12-week deductible period, for 52 weeks in the amount of $3 million per week at the Brunswick and Harris Plants and $2.5 million per week at the Robinson Plant. An additional 110 weeks of coverage is provided at 80% of the above weekly amounts. For the current policy period, PEC is subject to retrospective premium assessments of up to approximately $23 million with respect to the primary coverage, $27 million with respect to the decontamination, decommissioning and excess property coverage, and $15 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, PEC'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. PEC is responsible to the extent losses may exceed limits of the coverage described above.

PEC is insured against public liability for a nuclear incident up to $10.8 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, PEC, 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), PEC would be subject to pro rata assessments of up to $101 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 $10 million per reactor owned. Congress could possibly approve revisions to the Price Anderson Act during 2005 that could include increased limits and assessments per reactor owned. The final outcome of this matter cannot be predicted at this time.

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 the terrorist acts.

PEC self-insures its transmission and distribution lines against loss due to storm damage and other natural disasters.

5. CURRENT ASSETS

RECEIVABLES

At December 31, receivables were comprised of:

(in millions)	2004	2003
Trade accounts receivable	**$ 240**	$ 254
Unbilled accounts receivable	**155**	145
Other receivables	**12**	28
Allowance for doubtful accounts receivable	**(10)**	(17)
Total receivables	**$ 397**	$ 410

Income tax receivables and interest income receivables are not included in this classification. These amounts are included in prepayments and other current assets on the Consolidated Balance Sheets.

INVENTORY

At December 31, inventory was comprised of:

(in millions)	2004	2003
Fuel for production	**$ 127**	$ 117
Materials and supplies	**263**	270
Total inventory	**$ 390**	$ 387

6. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As a regulated entity, PEC is subject to the provisions of SFAS No. 71. Accordingly, PEC records certain assets and liabilities resulting from the effects of the ratemaking process that would not be recorded under GAAP for nonregulated entities. PEC's 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 applied to a separable portion of PEC's 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 (See Note 1D).

At December 31, the balances of PEC's regulatory assets (liabilities) were as follows:

(in millions)	2004	2003
Deferred fuel cost – current (Note 6B)	$ 140	$ 66
Deferred fuel cost – long-term (Note 6B)	28	47
Deferred impact of ARO (Note 1D)	305	291
Income taxes recoverable through future rates (Note 11)	36	33
Loss on reacquired debt (Note 1D)	22	22
Storm deferral (Note 3 and 6B)	25	21
Deferred DOE enrichment facilities-related costs	12	19
Other	45	30
Total long-term regulatory assets	473	463
Non-ARO cost of removal (Note 4D)	(671)	(968)
Emission allowance	(8)	(8)
Net nuclear decommissioning trust unrealized gains (Note 4D)	(125)	(99)
Clean air compliance (Note 6B)	(248)	(74)
Total long-term regulatory liabilities	(1,052)	(1,149)
Net regulatory assets (liabilities)	$ (439)	$ (620)

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

B. Retail Rate Matters

As of December 31, 2004, PEC's North Carolina retail fuel costs were under-recovered by $145 million. This amount is comprised of $117 million eligible for recovery in 2005 and $28 million deferred from a 2001 order from the NCUC that cannot be collected during 2005, and has therefore been classified as a long-term asset. PEC intends to collect this amount by October 31, 2007.

On October 15, 2004, the SCPSC approved PEC's request to leave fuel rates unchanged. The deferred fuel balance at December 31, 2004, is $23 million. This amount is eligible for recovery in PEC's 2005 South Carolina fuel review.

PEC obtained SCPSC and NCUC approval of fuel factors in annual fuel-adjustment proceedings. The NCUC approved an annual increase of $62 million, $20 million and $46 million by orders issued in September 2004, 2003 and 2002, respectively. The SCPSC approved PEC's petition each year and the changes were insignificant.

PEC filed with the SCPSC seeking permission to defer expenses incurred from the first quarter 2004 winter storm. 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.

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 ice storm and amortize them over a period of five years. PEC charged approximately $24 million in 2003 from Hurricane Isabel and from ice storms to the deferred account. PEC recognized $5 million and $3 million of NC storm amortization during 2004 and 2003, respectively.

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 2004 and 2003 and additional depreciation expense of approximately $53 million 2002. Total accelerated depreciation recorded through December 31, 2004 was $403 million.

The North Carolina Clean Smokestacks Act enacted in June 2002 (NC Clean Air), requires state utilities to reduce emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from coal-fired plants. The NCUC has allowed the utilities to amortize and recover the costs 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 when setting the amortization amount for each year. PEC recognized $174 million and $74 million of clean air amortization during 2004 and 2003, respectively. This legislation freezes PEC's base rates in North Carolina for five years, subject to certain conditions (See Note 17).

In conjunction with the Florida Progress Corporation (FPC) merger, PEC reached a settlement with the Public Staff of the NCUC in which it agreed to provide credits to its nonreal time pricing customers in the amounts of $3 million in 2002, $5 million in 2003 and $6 million in both 2004 and 2005.

In conjunction with the acquisition of NCNG in 1999, PEC agreed not to seek a base retail electric rate increase in North Carolina and South Carolina through December 2004. The agreement not to seek a base retail electric rate increase in South Carolina was extended to December 2005 in conjunction with regulatory approval to form a holding company.

C. Regional Transmission Organizations and Standard Market Design

In 2000, the FERC issued Order No. 2000 on RTOs, which set minimum characteristics and functions that RTOs must meet, including independent transmission service. In July 2002, the FERC issued its Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR). If adopted as proposed, the rules set forth in the SMD NOPR would have materially alter the manner in which transmission and generation services are provided and paid for. In April 2003, the FERC released a White Paper on the Wholesale Market Platform. The White Paper provided an overview of what the FERC intended to include in a final rule in the SMD NOPR docket. The White Paper retained the fundamental and most protested aspects of SMD NOPR, including mandatory RTOs and the FERC's assertion of jurisdiction over certain aspects of retail service. The FERC has not yet issued a final rule on SMD NOPR. PEC cannot predict the outcome of these matters or the effect that they may have on the GridSouth proceedings currently ongoing before the FERC. However, by order issued December 22, 2004, the FERC terminated a portion of the proceedings regarding GridSouth. The GridSouth Companies asked the FERC for further clarification to the portions of the GridSouth docket it intended to address. On March 2, 2005, the FERC affirmed that it only intended to close the mediation portion of the GridSouth docket. It is unknown what impact the future proceedings will have on PEC's earnings, revenues or prices.

PEC had $33 million invested in GridSouth related to startup costs at December 31, 2004. PEC expects to recover these startup costs in conjunction with the GridSouth original structure or in conjunction with any alternate combined transmission structures that emerge.

D. FERC Market Power Mitigation

A FERC order issued in November 2001 on certain unaffiliated utilities' triennial market-based wholesale power rate authorization updates required certain mitigation actions that those utilities would need to take for sales/purchases within their control areas and required those utilities to post information on their Web sites regarding their power systems' status. As a result of a request for rehearing filed by certain market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. 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. Given the difficulty PEC believes it would experience in passing one of the interim screens, on August 12, 2004, PEC notified the FERC that it would revise its Market-based Rate tariff to restrict it to sales outside PEC's control area and file a new cost-based tariff for sales within PEC's control area that incorporates the FERC's default cost-based rate methodologies for sales of one year or less. PEC anticipates making this filing first quarter of 2005. Although PEC cannot predict the ultimate outcome of these changes, PEC does not anticipate that its current operations would be impacted materially if PEC were unable to sell power at market-based rates in its respective control areas.

E. Energy Delivery Capitalization Practice

PEC has reviewed its capitalization policy for its Energy Delivery business unit. That review indicated that in the areas of outage and emergency work not associated with major storms and allocation of indirect costs, PEC should revise the way that it estimates the amount of capital costs associated with such work. PEC has implemented such changes effective January 1, 2005, which include more detailed classification of outage and emergency work and result in more precise estimation and a process of retesting 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 costs will be capitalized on a going forward basis. PEC estimates that the impact in 2005 will be that approximately $25 million of costs that would have been capitalized under the previous policies will be expensed. Pursuant to SFAS No. 71, PEC has informed the state regulators having jurisdiction over them of this change and that the new estimation process will be implemented effective January 1, 2005.

7. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

PEC applies SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. In 2003 and 2002, PEC recorded pre-tax long-lived asset and investment impairments and other charges of approximately $21 million and $133 million, respectively.

A. Long-Lived Assets

In 2002, PEC initiated an independent valuation study to assess the recoverability of Caronet's long-lived assets. Based on this assessment, PEC recorded asset impairments of $101 million on a pre-tax basis and other charges of $7 million on a pre-tax basis in the third quarter of 2002. This write-down constituted a significant reduction in the book value of these long-lived assets. The long-lived asset impairments included an impairment of property, plant and equipment, construction work in process and intangible assets. The impairment charge represents the difference between the fair value and carrying amount of these long-lived assets. The fair value of these assets was determined using a valuation study heavily weighted on the discounted cash flow methodology, while using market approaches as supporting information.

B. Investments

PEC continually reviews its investments to determine whether a decline in fair value below the cost basis is other than temporary. In 2003, PEC's affordable housing investment (AHI) portfolio was reviewed and deemed to be impaired based on various factors including continued operating losses of the AHI portfolio and management performance issues arising at certain properties within the AHI portfolio. As a result, PEC recorded an impairment on the AHI portfolio of $18 million on a pre-tax basis during the fourth quarter of 2003. PEC also recorded a pre-tax impairment of $3 million on a cost investment.

In May 2002, Interpath merged with a third party and PEC's ownership was diluted to approximately 19% of Interpath. As a result, PEC reviewed the Interpath investment for impairment and wrote off the remaining amount of its cost-basis investment in Interpath, recording a pre-tax impairment of $25 million in the third quarter of 2002. In the fourth quarter of 2002, PEC sold its remaining interest in Interpath for a nominal amount.

8. EQUITY

A. Capitalization

At December 31, 2004, PEC was authorized to issue up to 200 million shares of common stock. All shares issued and outstanding are held by Progress Energy.

Preferred stock outstanding at December 31, 2004 and 2003 consisted of the following (in millions except per share and par value):

Authorized – 300,000 shares, cumulative, $100 par value Preferred Stock; 20,000,000 shares, cumulative, $100 par value Serial Preferred Stock	
$5.00 Preferred – 236,997 shares (redemption price $110.00)	$ 24
$4.20 Serial Preferred – 100,000 shares outstanding redemption price $102.00)	10
$5.44 Serial Preferred –249,850 shares (redemption price $101.00)	25
Total Preferred Stock	$ 59

PEC's common stock increased by $22 million, $23 million and $26 million for the years ended December 31, 2004, 2003 and 2002, respectively, related primarily to the allocation of ESOP shares.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2004, there were no significant restrictions on the use of retained earnings.

PEC's Articles of Incorporation provide that cash dividends on common stock shall be limited to 75% of net income available for dividends if common stock equity falls below 25% of total capitalization, and to 50% if common stock equity falls below 20%. On December 31, 2004, PEC's common stock equity was approximately 52.2% of total capitalization. Refer to Note 9 for additional dividend restrictions related to PEC's mortgage.

B. Stock-Based Compensation Plans

EMPLOYEE STOCK OWNERSHIP PLAN

Progress Energy sponsors the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining employees within participating subsidiaries are eligible. PEC is a participating subsidiary of 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 stock 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 Progress Energy matching and incentive contributions and/or reinvested dividends.

There were 3.5 million and 4.0 million ESOP suspense shares at December 31, 2004 and 2003, respectively, with a fair value of $156 million and $183 million, respectively. PEC's 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. The 401(k) common stock share needs are met 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 with shares in the following year; costs for the matching component are typically met with shares in the same year incurred. PEC's matching and incentive cost, which were and will be met with shares released from the suspense account, totaled approximately $12 million, $11 million and $13 million for the years ended December 31, 2004, 2003 and 2002, respectively. Matching and incentive cost totaled approximately $18 million, $16 million and $14 million for the years ended December 31, 2004, 2003 and 2002, respectively. PEC has a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from PEC in 1989 (now Progress Energy common stock). 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. Interest income on the note receivable is not recognized for financial statement purposes.

STOCK OPTION AGREEMENTS

Pursuant to Progress Energy's 1997 Equity Incentive Plan and 2002 Equity Incentive Plan, as amended and restated as of July 10, 2002, Progress Energy may grant options to purchase shares of common stock to directors, officers and eligible employees. For the years ended December 31, 2004, 2003 and 2002, respectively, approximately 28 thousand, 3.0 million and 2.9 million common stock options were granted. Of these amounts, approximately 1.9

million and 1.2 million options were granted to officers and eligible employees of PEC in 2003 and 2002, respectively. No stock options were granted to officers and employees of PEC in 2004. PEC expects to begin expensing stock options on July 1, 2005, by adopting new FASB guidance on accounting for stock-based compensation (See Note 2). In 2004, however, Progress Energy made the decision to cease granting stock options and intends to replace that compensation program with other programs. Therefore, the amount of stock option expense expected to be recorded in 2005 is below the amount that would have been recorded if the stock option program had continued.

The pro forma information presented in Note 1D regarding net income is required by SFAS No. 148. Under this statement, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The pro forma amounts presented in Note 1D have been determined as if PEC had accounted for its employee stock options under SFAS No. 123.

OTHER STOCK-BASED COMPENSATION PLANS

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

Under the terms of the PSSP, officers and key employees are granted 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's 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 Progress Energy's results as compared to a peer group of utilities. Compensation expense is recognized over the vesting period based on the expected ultimate cash payout and is reduced by any forfeitures.

The RSA program allows Progress Energy to grant shares of restricted common stock to officers and key employees of PEC. 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 and is reduced by any forfeitures.

The total amount expensed by PEC for other stock-based compensation plans was $7 million, $15 million and $11 million in 2004, 2003 and 2002, respectively.

C. Accumulated Other Comprehensive Loss

Components of accumulated other comprehensive loss are as follows:

(in millions)	2004	2003
Loss on cash flow hedges	$ (7)	$ (6)
Minimum pension liability adjustments	(107)	(1)
Total accumulated other comprehensive loss	$ (114)	$ (7)

9. DEBT AND CREDIT FACILITIES

A. Debt and Credit

At December 31, PEC's long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2004):

(in millions)		2004	2003
First mortgage bonds, maturing 2005-2033	6.33%	$ 1,600	$ 1,900
Pollution control obligations, maturing 2017-2024	1.98%	669	708
Unsecured notes, maturing 2012	6.50%	500	500
Medium-term notes, maturing 2008	6.65%	300	300
Unamortized premium and discount, net		(19)	(22)
Current portion of long-term debt		(300)	(300)
Total Long-Term Debt, Net		$ 2,750	$ 3,086

At December 31, 2004, PEC had committed lines of credit, which are used to support its commercial paper borrowings and are included in short-term obligations. At December 31, 2004, the weighted average interest rate on borrowings under the lines of credit was 3.29%. PEC is required to pay minimal annual commitment fees to maintain its credit facilities.

The following table summarizes PEC's credit facilities (in millions):

Description	Total	Outstanding	Available
364-Day (expiring 7/27/05)	$ 165	$ 90	$ 75
3-Year (expiring 7/31/05)	285	–	285
Less: amounts reserved(a)			(131)
	$ 450	$ 90	$ 229

(a) To the extent amounts are reserved for commercial paper outstanding or backing letters of credit, they are not available for additional borrowings.

At December 31, 2004 and 2003, PEC had $131 million and $4 million, respectively, of outstanding commercial paper and other short-term debt classified as short-term obligations. The weighted-average interest rates of such short-term obligations at December 31, 2004 and 2003 were 2.77% and 2.25%, respectively.

The combined aggregate maturities of long-term debt for 2005 through 2009 are approximately, in millions, $300, $0, $200, $300 and $400, respectively.

B. Covenants and Default Provisions

FINANCIAL COVENANTS

PEC's credit line contains various terms and conditions that could affect PEC's ability to borrow under these facilities. These include a maximum debt to total capital ratio, a material adverse change clause and a cross-default provision.

PEC's credit line requires a maximum total debt to total capital ratio of 65%. Indebtedness as defined by the bank agreement includes certain letters of credit and guarantees that are not recorded on the Consolidated Balance Sheets. At December 31, 2004, PEC's total debt to total capital ratio was 52.3%.

MATERIAL ADVERSE CHANGE CLAUSE

The credit facility of PEC includes a provision under which lenders could refuse to advance funds in the event of a material adverse change in the borrower's financial condition.

CROSS-DEFAULT PROVISIONS

PEC's credit lines include cross-default provisions for defaults of indebtedness in excess of $10 million. PEC's cross-default provisions only apply to defaults of indebtedness by PEC and its subsidiaries, respectively, and not to other affiliates of PEC. In addition, the credit lines of Progress Energy include a similar provision. Progress Energy's cross-default provisions apply only to defaults of indebtedness by Progress Energy and its significant subsidiaries, which includes PEC.

The lenders may accelerate payment of any outstanding debt if cross-default provisions are triggered. Any such acceleration would cause a material adverse change in the respective company's financial condition. Certain agreements underlying PEC's indebtedness also limit PEC's ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

PEC's mortgage indenture provides that, as long as any first mortgage bonds are outstanding, cash dividends and distributions on PEC's common stock and purchases of PEC's 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, 2004, none of PEC's retained earnings was restricted. Refer to Note 8 for additional dividend restrictions related to PEC's Articles of Incorporation.

C. Collateralized Obligations

PEC's first mortgage bonds are collateralized by their respective mortgage indentures. PEC's mortgage constitutes a first lien on substantially all of its fixed properties, subject to certain permitted encumbrances and exceptions. The PEC mortgage also constitutes a lien on subsequently acquired property. At December 31, 2004, PEC had approximately $2.269 billion in first mortgage bonds outstanding, including those related to pollution control obligations. The PEC mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Hedging Activities

PEC uses interest rate derivatives to adjust the fixed and variable rate components of its debt portfolio and to hedge cash flow risk of fixed rate debt to be issued in the future. See discussion of risk management and derivative transactions at Note 13.

10. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts of cash and cash equivalents and short-term obligations approximate fair value due to the short maturities of these instruments. At December 31, 2004 and 2003, there were miscellaneous investments consisting primarily of investments in company-owned life insurance and other benefit plan assets with carrying amounts totaling approximately $94 million and $90 million, respectively, included in miscellaneous other property and investments in the Consolidated Balance Sheets. The carrying amount of these investments approximates fair value due to the short maturity of certain instruments. Other instruments, including short-term investments, are presented at fair value in accordance with GAAP. The carrying amount of PEC's long-term debt, including current maturities, was $3.050 billion and $3.386 billion at December 31, 2004 and 2003, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.307 billion and $3.686 billion at December 31, 2004 and 2003, respectively.

External trust funds have been established to fund certain costs of nuclear decommissioning. These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents. 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.

11. INCOME TAXES

Deferred income taxes have been provided for temporary differences. These occur when there are differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes under SFAS No. 109, "Accounting for Income Taxes," (SFAS No. 109) is different from the recovery of taxes by PEC 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 utility pursuant to rate orders.

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

(in millions)	2004	2003
Current deferred tax asset – other		
Included in prepayments and other current assets	36	16
Noncurrent deferred tax asset (liability)		
Investments	4	5
Supplemental executive retirement plans	9	7
Other post-employment benefits (OPEB)	52	46
Other pension plans	56	(8)
Income tax credit carry forward	21	22
Accumulated depreciation and property cost differences	(960)	(1,066)
Deferred costs	(13)	26
Deferred fuel	(55)	31
Valuation allowance	(1)	(1)
Miscellaneous other temporary differences, net	(1)	(39)
Total noncurrent deferred tax liability	(888)	(977)

Total deferred income tax liabilities were $1,713 million and $1,758 million at December 31, 2004 and 2003, respectively. Total deferred income tax assets were $861 million and $797 million at December 31, 2004 and 2003, respectively. Total noncurrent income tax liabilities on the Consolidated Balance Sheets at December 31, 2004 and 2003 include $103 million and $80 million, respectively, related to probable tax liabilities, on which PEC accrues interest that would be payable with the related tax amount in future years. All tax contingency reserves relate to capitalization and basis issues.

The federal income tax credit carry forward at December 31, 2004 consists of $21 million of general business credit with a carry forward period that will begin to expire in 2020.

PEC did not establish any additional valuation allowances in 2004. PEC established additional valuation allowances of $1 million and $4 million during 2003 and 2002, respectively, due to the uncertainty of realizing certain future state tax benefits. PEC believes that it is more likely than not that the results of future operations will generate sufficient taxable income to allow for the utilization of the remaining deferred tax assets.

Reconciliations of PEC's effective income tax rate to the statutory federal income tax rate are:

	2004	2003	2002
Effective income tax rate	34.1%	32.3%	32.5%
State income taxes, net of federal benefit	(2.9)	(1.9)	(3.1)
Investment tax credit amortization	1.1	1.4	1.9
Progress Energy tax benefit allocation	3.0	3.0	5.0
AFUDC amortization	(0.5)	(1.5)	(5.8)
Other differences, net	0.2	1.7	4.5
Statutory federal income tax rate	35.0%	35.0%	35.0%

Income tax expense (benefit) applicable to continuing operations is comprised of:

(in millions)	2004	2003	2002
Income tax expense (credit):			
Current – federal	$232	$ 283	$ 265
state	33	37	36
Deferred – federal	(18)	(56)	(76)
state	(1)	(13)	(6)
Investment tax credit	(7)	(10)	(12)
Total income tax expense	$239	$ 241	$ 207

PEC and each of its wholly owned subsidiaries have entered into a Tax Agreement with Progress Energy (See Note 1D). PEC's intercompany tax receivable was $62 million and $40 million at December 31, 2004 and 2003, respectively.

12. BENEFIT PLANS

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

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

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2004	2003	2002	2004	2003	2002
Service cost	$ 24	$ 23	$ 19	$ 6	$ 7	$ 6
Interest cost	52	51	51	15	15	14
Expected return on plan assets	(69)	(70)	(73)	(4)	(3)	(3)
Amortization, net	1	–	1	3	5	2
Net periodic cost / (benefit)	$ 8	$ 4	$ (2)	$ 20	$ 24	$ 19

Net periodic cost for other postretirement benefits decreased during 2004 due to the implementation of FASB Staff Position 106-2 (See Note 2).

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% of the greater of the obligation or the market-related value of assets are amortized over the average remaining service period of active participants. PEC uses a five-year averaging method to determine its market-related value of assets.

Reconciliations of the changes in the plans' benefit obligations and the plans' funded status are:

	Pension Benefits				Other Postretirement Benefits			
(in millions)	2004		2003		2004		2003	
Obligation at January 1	$	837	$	802	$	218	$	234
Service cost		24		23		6		7
Interest cost		52		51		15		15
Plan amendment		14		–		–		–
Benefit payments		(50)		(46)		(5)		(8)
Actuarial loss (gain)		51		7		28		(30)
Obligation at December 31		928		837		262		218
Fair value of plan assets at December 31		753		694		45		43
Funded status		(175)		(143)		(217)		(175)
Unrecognized transition obligation		–		–		9		23
Unrecognized prior service cost		18		4		–		–
Unrecognized net actuarial (gain) loss		181		150		36		(1)
Minimum pension liability adjustment		(194)		(2)		–		–
Prepaid (accrued) cost at December 31, net	$	(170)	$	9	$	(172)	$	(153)

The 2003 OPEB obligation information above has been restated due to the implementation of FASB Staff Position 106-2 (See Note 2).

The net accrued pension cost of $170 million at December 31, 2004, is included in accrued pension and other benefits in the Consolidated Balance Sheets. The net prepaid pension cost of $9 million at December 31, 2003, is recognized in the Consolidated Balance Sheets as prepaid pension cost of $28 million, which is included in other assets and deferred debits, and accrued benefit cost of $19 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 $928 million and $22 million at December 31, 2004 and 2003, respectively. Those plans had accumulated benefit obligations totaling $923 million and $19 million, at December 31, 2004 and 2003, respectively, plan assets of $753 million at December 31, 2004 and no plan assets at December 31, 2003. The total accumulated benefit obligation for pension plans was $923 million and $834 million at December 31, 2004 and 2003, respectively. The accrued OPEB cost is included in accrued pension and other benefits in the Consolidated Balance Sheets.

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. A minimum pension liability adjustment of $2 million was recorded at December 31, 2003. This adjustment was offset by a corresponding pre-tax charge to accumulated other comprehensive loss, a component of common stock equity.

Reconciliations of the fair value of plan assets are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2004	2003	2004	2003
Fair value of plan assets January 1	$ 693	$ 574	$ 43	$ 33
Actual return on plan assets	89	165	5	10
Benefit payments	(50)	(46)	(5)	(8)
Employer contributions	21	1	2	8
Fair value of plan assets at December 31	$ 753	$ 694	$ 45	$ 43

In the table above, substantially all employer contributions represent benefit payments made directly from PEC assets except for the 2004 pension amount. The remaining benefits payments were made directly from plan assets. In 2004, PEC made a contribution directly to pension plan assets of approximately $20 million, which represented its allocated share of a required Progress Energy contribution. The OPEB benefit payments represent the net PEC cost after participant contributions. Participant contributions represent approximately 40% of gross benefit payments.

The asset allocation for PEC's plans at the end of 2004 and 2003 and the target allocation for the plans, by asset category, are as follows:

	Pension Benefits			Other Postretirement Benefits		
	Target Allocations	Percentage of Plan Assets at Year End		Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2005	2004	2003	2005	2004	2003
Equity – domestic	48%	47%	49%	48%	47%	49%
Equity – international	15%	21%	22%	15%	21%	22%
Debt – domestic	12%	9%	11%	12%	9%	11%
Debt – international	10%	11%	11%	10%	11%	11%
Other	15%	12%	7%	15%	12%	7%
Total	100%	100%	100%	100%	100%	100%

PEC sets 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, PEC employs external investment managers who have complementary investment philosophies and approaches. Tactical shifts (plus or minus 5%) 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.

In 2005, PEC expects to make no contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2005 through 2009 and in total for 2010-2014, in millions, are approximately \$59, \$57, \$58, \$62, \$64 and \$375, respectively. The expected benefit payments for the OPEB plan for 2005 through 2009 and in total for 2010-2014, in millions, are approximately \$14, \$15, \$16, \$16, \$17, and \$98, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from Company 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 (See Note 2), and the expected subsidies for 2006 through 2009 and in total for 2010-2014, in millions, are approximately \$1, \$1, \$1, \$2 and \$10, respectively. The expected benefit payments above do not reflect the potential effects of the 2005 voluntary enhanced retirement program (See Note 18).

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

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
Discount rate	5.90%	6.30%	5.90%	6.30%
Rate of increase in future compensation – supplementary plan	5.25%	5.00%	–	–
Initial medical cost trend rate for pre-Medicare benefits	–	–	7.25%	7.25%
Initial medical cost trend rate for post-Medicare benefits	–	–	7.25%	7.25%
Ultimate medical cost trend rate	–	–	5.00%	5.25%
Year ultimate medical cost trend rate is achieved	–	–	2008	2009

PEC's primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4. Therefore, effective December 31, 2003, PEC 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.

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

	Pension Benefits			Other Postretirement Benefits		
	2004	2003	2002	**2004**	2003	2002
Discount rate	**6.30%**	6.60%	7.50%	**6.30%**	6.60%	7.50%
Rate of increase in future compensation – nonbargaining	**–**	4.00%	4.00%	**–**	–	–
Rate of increase in future compensation – supplementary plan	**5.00%**	4.00%	4.00%	**–**	–	–
Expected long-term rate of return on plan assets	**9.25%**	9.25%	9.25%	**9.25%**	9.25%	9.25%

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 allocations. Those benchmarks support an expected long-term rate of return between 9.0% and 9.5%. PEC has chosen to use an expected long-term rate of 9.25%.

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. Assuming a 1% increase in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2004 would increase by $1 million, and the OPEB obligation at December 31, 2004, would increase by $14 million. Assuming a 1% decrease in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2004 would decrease by $1 million and the OPEB obligation at December 31, 2004, would decrease by $13 million.

13. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

Under its risk management policy, PEC 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. PEC minimizes 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 the consolidated financial position or consolidated results of operations of PEC.

A. Commodity Derivatives

GENERAL

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

During 2003 the FASB reconsidered an interpretation of SFAS No. 133 related to the pricing of contracts that include broad market indices (e.g., CPI). In particular, that guidance discussed whether the pricing in a contract that contains broad market indices could qualify as a normal purchase or sale (the normal purchase or sale term is a defined accounting term, and may not, in all cases, indicate whether the contract would be "normal" from an operating entity viewpoint). The FASB issued final superseding guidance (DIG Issue C20) on this issue effective October 1, 2003, for PEC. DIG Issue C20 specifies new pricing-related criteria for qualifying as a normal purchase or sale, and it required a special transition adjustment as of October 1, 2003.

PEC determined that it had one existing "normal" contract that was affected by DIG Issue C20. Pursuant to the provisions of DIG Issue C20, PEC recorded a pre-tax fair value loss transition adjustment of $38 million ($23 million after-tax) in the fourth quarter of 2003, which was reported as a cumulative effect of a change in accounting principle. The subject contract meets the DIG Issue C20 criteria for normal purchase or sale and, therefore, was designated as a normal purchase as of October 1, 2003. The original liability of $38 million associated with the fair value loss is being amortized to earnings over the term of the related contract. At December 31, 2004 and 2003, the remaining liability was $26 million and $35 million, respectively.

ECONOMIC DERIVATIVES

Derivative products, primarily electricity and natural gas contracts, are entered into 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. PEC manages open positions with strict policies that limit its exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material to results of operations during 2004, 2003 or 2002, and PEC did not have material outstanding positions in such contracts at December 31, 2004 or 2003.

CASH FLOW HEDGES

PEC uses cash flow hedging strategies to hedge variable interest rates on long-term and short-term debt and to hedge interest rates with regard to future fixed-rate debt issuances. As of December 31, 2004, PEC had $110 million notional amount of pay-fixed forward swaps to hedge its exposure to interest rates with regard to future issuances of debt (pre-issue hedges) and $21 million notional amount of pay-fixed forward starting swaps to hedge its exposure to interest rates with regard to an upcoming railcar lease. On February 4, 2005, PEC entered another $50 million notional amount of its pre-issue hedges. All the swaps have a computational period of ten years. These hedges had a fair value liability position of $2 million at December 31, 2004. PEC had no open cash flow hedges at December 31, 2003. The ineffective portion of interest rate cash flow hedges was not material to PEC's results of operations in 2004. As of December 31, 2004, PEC had $7 million of after-tax deferred losses in accumulated other comprehensive income (OCI), including amounts related to terminated hedges, of which $1 million is expected to be reclassified to earnings within the next 12 months. Due to the volatility of interest rates, the value in OCI is subject to change prior to its reclassification into earnings.

FAIR VALUE HEDGES

PEC uses fair value hedging strategies to manage its exposure to fixed interest rates on long-term debt. At December 31, 2004 and 2003, PEC had no open interest rate fair value hedges.

The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by a counterparty, the risk in these transactions is the cost of replacing the agreements at current market rates.

14. RELATED PARTY TRANSACTIONS

The Company's subsidiaries provide and receive services, at cost, to and from Progress Energy and its subsidiaries, in accordance with agreements approved by the U.S. Securities and Exchange Commission (SEC) pursuant to Section 13(b) of the PUHCA. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, constructions 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 Consolidated Balance Sheets.

Progress Energy Service Company, LLC, (PESC) provides the majority of the affiliated services under the approved agreements. Service provided by PESC during 2004, 2003 and 2002 to PEC amounted to $209 million, $184 million and $198 million, respectively. Based on a standard review by the Office of Public Utility Regulation within the SEC the method for allocating certain PESC governance costs changed and retroactive reallocations for 2002 and 2001 charges were recorded in 2003. The net after-tax impact of the reallocation of costs was a reduction of expenses at PEC by $10 million.

PEC and an affiliated utility also provide and receive services at cost. Services provided by PEC during 2004, 2003 and 2002 amount to $52 million, $35 million and $72 million, respectively. Services received by PEC during 2004, 2003 and 2002 amount to $16 million, $7 million and $16 million, respectively.

To facilitate commercial transactions of Progress Energy's subsidiaries, Progress Energy and certain wholly owned subsidiaries enter into agreements providing future financial or performance assurances to third parties. As of December 31, 2004, Progress Energy's guarantees include $181 million to support nuclear decommissioning. PEC determined that its external funding levels did not fully meet the nuclear decommissioning financial assurance levels required by NRC, therefore PEC obtained parent company guarantees. The Company and PEC also purchased $43 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $4 million on behalf of PEC.

PEC participates 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 1.72%, 1.47% and 2.18% at December 31, 2004, 2003 and 2002, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Consolidated Balance Sheets. PEC recorded insignificant interest expense related to the money pool for all the years presented.

The Company sold North Carolina Natural Gas Corporation (NCNG) to Piedmont Natural Gas Company, Inc., on September 30, 2003. During the years ended December 31, 2003 and 2002, gas sales from NCNG to PEC amounted to $11 million and $18 million, respectively. The gas sales for 2003 indicated above exclude any sales subsequent to September 2003. Strategic Resource Solutions, Corp. and its subsidiary, which were wholly owned until 2004, managed subcontracts for PEC. Amounts for the three years presented were not significant. PEC has entered into a Tax Agreement with Progress Energy (See Note 11).

15. FINANCIAL INFORMATION BY BUSINESS SEGMENT

PEC's operations consist primarily of the PEC Electric segment, which is engaged in the generation, transmission, distribution and sale of electric energy primarily in portions of North Carolina and South Carolina. These electric operations are subject to the rules and regulations of the FERC, the NCUC, the SCPSC and the NRC.

The Other segment, whose operations are primarily in the United States, is made up of other nonregulated business areas including 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" and consolidation entities and eliminations. Included are the operations of Caronet, which recognized an $87 million after-tax asset and investment impairment in 2002.

(in millions)	PEC Electric	Other	Total
Year Ended December 31, 2004			
Revenues	**$ 3,628**	**$ 1**	**$ 3,629**
Depreciation and amortization	**570**	**–**	**570**
Total interest charges, net	**192**	**–**	**192**
Income tax expense	**237**	**2**	**239**
Income (loss) excluding cumulative effect	**464**	**(6)**	**458**
Total segment assets	**10,590**	**197**	**10,787**
Capital and investment expenditures	**519**	**–**	**519**
Year Ended December 31, 2003			
Revenues	$ 3,589	$ 11	$ 3,600
Depreciation and amortization	562	1	563
Total interest charges, net	197	–	197
Impairment of long-lived assets & investments	11	10	21
Income tax expense	238	3	241
Income (loss) excluding cumulative effect	515	(13)	502
Total segment assets	10,748	190	10,938
Capital and investment expenditures	445	1	446
Year Ended December 31, 2002			
Revenues	$ 3,539	$ 15	$ 3,554
Depreciation and amortization	524	4	528
Total interest charges, net	212	–	212
Impairment of long-lived assets & investments	–	126	126
Income tax expense (benefit)	237	(30)	207
Income (loss) excluding cumulative effect	513	(85)	428
Total segment assets	10,139	266	10,405
Capital and investment expenditures	619	12	631

16. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income, impairment of investments and other income and expense items as discussed below. The components of other, net, as shown on the Consolidated Statements of Income for years ended December 31, are as follows:

(in millions)	2004	2003	2002
Other income			
Nonregulated energy and delivery services income	$ 15	$ 12	$ 16
DIG Issue C20 amortization (Note 13A)	9	2	–
AFUDC equity	4	2	6
Gain on sale of property	12	6	3
Other	2	–	16
Total other income	$ 42	$ 22	$ 41
Other expense			
Nonregulated energy and delivery services expenses	$ 9	$ 9	$ 14
Donations	7	6	7
Losses from Equity Investments	1	16	7
Other	14	2	–
Total other expense	$ 31	$ 33	$ 28
Other, net	11	(11)	13

Nonregulated energy and delivery services include power protection services and mass market programs (surge protection, appliance services and area light sales) and delivery, transmission and substation work for other utilities.

17. ENVIRONMENTAL MATTERS

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

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North and South Carolina, have similar types of legislation. PEC is periodically notified by regulators including the EPA and various state agencies of their involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which PEC has been notified by the EPA and the State of North Carolina of its potential liability, as described below in greater detail. PEC is also currently in the process of assessing potential costs and exposures at other sites. For all sites, assessments are developed and analyzed, PEC will accrue costs for the sites to the extent the costs are probable and can be reasonably estimated.

Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. The principal regulatory agency that is responsible for a specific former manufactured gas plant (MGP) site depends largely upon the state in which the site is located. There are several MGP sites to which PEC has some connection. In this regard, PEC and other potentially responsible parties (PRPs) are participating in, investigating and, if necessary, remediating former MGP sites with several regulatory agencies, including, but not limited to, the U.S. Environmental Protection Agency (EPA) and the North Carolina Department of Environment and Natural Resources, Division of Waste Management (DWM).

PEC has filed claims with its general liability insurance carriers to recover costs arising from actual or potential environmental liabilities. All claims have been settled other than with insolvent carriers. These settlements have not had a material effect on the consolidated financial position or results of operations.

ENVIRONMENTAL LIABILITIES

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 costs.

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, North Carolina. The EPA offered PEC and 34 other PRPs the opportunity to negotiate cleanup of the site and reimbursement of less than $2 million to the EPA for EPA's 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 Ward Transformer site.

At December 31, 2004 and 2003, 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 many years, were:

(in millions)	2004	2003
Insurance fund	$ 7	$ 9
Transferred from NCNG at time of sale	2	2
Total accrual for environmental sites	$ 9	$ 11

PEC received insurance proceeds to address costs associated with environmental liabilities related to its involvement with some sites. All eligible expenses related to these are charged against a specific fund containing these proceeds. PEC spent approximately $2 million related to environmental remediation in 2004. PEC is unable to provide an estimate of the reasonably possible total remediation costs beyond what is currently accrued due to the fact that investigations have not been completed at all sites.

This accrual has been recorded on an undiscounted basis. PEC measures its liability for these sites based on available evidence including its experience in investigating and remediating environmentally impaired sites. The process often involves assessing and developing cost-sharing arrangements with other PRPs. PEC will accrue costs for the sites to the extent its 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, PEC cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is anticipated that sufficient information will become available for several sites during 2005 to allow a reasonable estimate of PEC's obligation for those sites to be made.

AIR QUALITY

Congress is considering legislation that would require reductions in air emissions of NOx, SO_2, carbon dioxide and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multi-pollutant approach to air pollution control could involve significant capital costs, which could be material to PEC's consolidated financial position or results of operations. Control equipment that will be installed on North Carolina fossil generating facilities as part of the NC Clean Air legislation discussed below may address some of the issues outlined above. However, PEC cannot predict the outcome of this matter.

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 New Source Review requirements or New Source Performance Standards under the Clean Air Act. PEC was 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 other 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 cost through rate adjustments or similar mechanisms. PEC cannot predict the outcome of this matter.

In 2003, the EPA published a final rule addressing routine equipment replacement under the New Source Review program. The rule defines routine equipment replacement and the types of activities that are not subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. The rule was challenged in the Federal Appeals Court and its implementation stayed. In July 2004, the EPA announced it will reconsider certain issues arising from the final routine equipment replacement rule. The comment period closed on August 30, 2004. PEC cannot predict the outcome of this matter.

In 1998, the EPA published a final rule under Section 110 of the Clean Air Act addressing the regional transport of ozone (NOx SIP Call). Total capital expenditures to meet the requirements of the NOx SIP Call Rule in North and South Carolina could reach approximately $370 million. PEC has spent approximately $282 million to date related to these projected amounts. Increased operation and maintenance costs relating to the NOx SIP Call are not expected to be material to PEC's results of operations. Further controls are anticipated as electricity demand increases.

In 1997, the EPA issued final regulations establishing a new 8-hour ozone standard. In April 2004, the EPA identified areas that do not meet the standard. The states with identified areas, including North and South Carolina, are proceeding with the implementation of the federal 8-hour ozone standard. Both states promulgated final regulations, which will require PEC to install NOx controls under the states' programs to comply with the 8-hour standard. The costs of those controls are included in the $370 million cost estimate above. However, further technical analysis and rulemaking may result in requirements for additional controls at some units. PEC cannot predict the outcome of this matter.

In June 2002, the NC Clean Air legislation was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from coal-fired power plants. Progress Energy projects that its capital costs to meet these emission targets will total approximately $895 million by the end of 2013. PEC has expended approximately $108 million of these capital costs through December 31, 2004. PEC currently has approximately 5,100 MW of coal-fired generation capacity in North Carolina that is affected by this Act. The law requires the emissions reductions to be completed in phases by 2013, and applies to each utility's total system rather than setting requirements for individual power plants. The law also freezes the utilities' base rates for five years 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 law requires PEC to amortize $569 million, representing 70% of the original cost estimate of $813 million, during the five-year rate freeze period. PEC recognized amortization of $174 million and $74 million for the years ended December 31, 2004, and 2003, respectively, and has recognized $248 million in cumulative amortization through December 31, 2004. The remaining amortization requirement of $321 million will be recorded over the three-year period ending December 31, 2007. The law 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 law, 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 law. The law also requires the State to undertake a study of mercury and carbon dioxide emissions in North Carolina. Operation and maintenance costs will increase due to the additional personnel, materials and general maintenance associated with the equipment. Operation and maintenance expenses are recoverable through base rates, rather than as part of this program. PEC cannot predict the future regulatory interpretation, implementation or impact of this law.

In 1997, the EPA's Mercury Study Report and Utility Report to Congress concluded that mercury is not a risk to the average person in America and expressed uncertainty about whether reductions in mercury emissions from coal-fired power plants would reduce human exposure. Nevertheless, the EPA determined in 2000 that regulation of mercury emissions from coal-fired power plants was appropriate. In 2003, the EPA proposed alternative control plans that would limit mercury emissions from coal-fired power plants. The final rule was released on March 15, 2005. The EPA's rule establishes a mercury cap and trade program for coal-fired power plants that requires limits to be met in two phases, in 2010 and 2018. PEC is reviewing the final rule. Installation of additional air quality controls is likely to be needed to meet the mercury rule's requirements. Compliance plans and the cost to comply with the rule will be determined once PEC completes its review.

In conjunction with the proposed mercury rule, the EPA proposed a MACT standard to regulate nickel emissions from residual oil-fired units. The agency estimates the proposal will reduce national nickel emissions to approximately 103 tons. PEC does not have units impacted by this proposal. The EPA expects to finalize the nickel rule in March 2005.

In December 2003, the EPA released its proposed Interstate Air Quality Rule, currently referred to as the Clean Air Interstate Rule (CAIR). The final rule was released on March 10, 2005. The EPA's rule requires 28 states and the District of Columbia, including North Carolina and South Carolina, to reduce NOx and SO_2 emissions in order to attain preset state NOx and SO_2 emissions levels. PEC is reviewing the final rule. Installation of additional air quality controls is likely to be needed to meet the CAIR requirements. Compliance plans and the cost to comply with the rule will be determined once PEC completes its review. The air quality controls already installed for compliance with the NOx SIP Call and currently planned by PEC to comply with the NC Clean Air legislation will reduce the costs required to meet the CAIR requirements for PEC's North Carolina units.

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. The EPA has agreed to make a determination on the petition by August 1, 2005. PEC cannot predict the outcome of this matter.

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 PEC in the immediate and extended future.

After many years of litigation and settlement negotiations, the EPA adopted regulations in February 2004 to implement Section 316(b) of the Clean Water Act. These regulations became effective September 7, 2004. The purpose of these regulations is to minimize adverse environmental impacts caused by cooling water intake structures and intake systems. Over the next several years these regulations will impact the larger base load generation facilities and may require the facilities to mitigate the effects to aquatic organisms by constructing intake modifications or undertaking other restorative activities. PEC currently estimates that from 2005 through 2009 the range of its expenditures to meet the Section 316(b) requirements of the Clean Water Act will be $20 million to $30 million.

OTHER ENVIRONMENTAL MATTERS

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of carbon dioxide and other greenhouse gases. In 2004, Russia ratified the Protocol, and 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. A number of carbon dioxide emissions control proposals have been advanced in Congress. Reductions in carbon dioxide emissions to the levels specified by the Kyoto Protocol and some legislative proposals could be materially adverse to PEC's consolidated financial position or results of operations if associated costs of control or limitation cannot be recovered from customers. PEC favors the voluntary program approach recommended by the administration and continually evaluates options for the reduction, avoidance and sequestration of greenhouse gases. However, PEC cannot predict the outcome of this matter.

Progress Energy has announced its plan to issue a report on it's activities associated with current and future environmental requirements. The report will include a discussion of the environmental requirements that the PEC currently faces and expects to face in the future, as well as an assessment of potential mandatory constraints on carbon dioxide emissions. The report will be issued by March 31, 2006.

18. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

The following table reflects PEC's contractual cash obligations and other commercial commitments at December 31, 2004, in the respective periods in which they are due.

(in millions)	2005	2006	2007	2008	2009	Thereafter
Fuel	$ 649	$ 450	$ 393	$ 126	$ 135	$ 586
Purchased power	137	130	125	84	86	526
Other Purchase Obligations	12	–	–	–	–	13
Total	$ 798	$ 580	$ 518	$ 210	$ 221	$ 1,125

FUEL AND PURCHASED POWER

PEC has entered into various long-term fuel contracts for coal, oil and gas requirements of its generating plants. Total payments under these commitments were $477 million, $562 million and $524 million in 2004, 2003 and 2002, respectively.

Pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between PEC and the North Carolina Eastern Municipal Power Agency (Power Agency), PEC is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, the Harris Plant. 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 the Harris Plant, 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 $38 million. These contractual purchases totaled $39 million, $36 million and $36 million for 2004, 2003 and 2002, respectively. In 1987, the NCUC ordered PEC to reflect the recovery of the capacity portion of these costs on a levelized basis over the original 15-year buyback period, thereby deferring for future recovery the difference between such costs and amounts collected through rates. In 1988, the SCPSC ordered similar treatment, but with a 10-year levelization period. At December 31, 2004, all previously deferred costs have been expensed.

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 $43 million, representing capital-related capacity costs. Estimated annual payments for energy and capacity costs are approximately $72 million through 2009. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $63 million, $66 million and $59 million for 2004, 2003 and 2002, respectively.

PEC executed two long-term agreements for the purchase of power from Broad River LLC's Broad River facility. 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 300 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 $42 million, $37 million and $38 million in 2004, 2003 and 2002 respectively.

PEC has various pay-for-performance purchased power contracts with certain cogenerators (qualifying facilities) for approximately 400 MW of capacity expiring at various times through 2012. These purchased power contracts generally provide for capacity and energy payments. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $91 million, $113 million and $145 million in 2004, 2003 and 2002, respectively.

CONSTRUCTION OBLIGATIONS

At December 31, 2004, PEC has no construction obligations. Total purchases under various combustion turbine construction obligations were $5 million, $21 million and $13 million for 2004, 2003 and 2002, respectively.

OTHER CONTRACTUAL OBLIGATIONS

On December 31, 2002, PEC entered into a contractual commitment to purchase at least $13 million of capital parts by December 31, 2010. During 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 storages. Total purchases under these contracts were $17 million for 2004 and $3 million for 2003. Future purchase obligations are $12 million for 2005.

PEC incurred expenses related to various other purchase obligations allocated from PESC of $8 million for 2004 and 2003 and $4 million for 2002.

B. Leases

PEC leases office buildings, computer equipment, vehicles, and other property and equipment with various terms and expiration dates. Rent expense under operating leases totaled $20 million for 2004 and 2003 and $22 million for 2002. These amounts include rent expense allocated from PESC of $11 million, $10 million and $12 million for 2004, 2003 and 2002, respectively. Purchased power expense under agreements classified as operating leases were approximately $24 million during 2004 and $5 million during 2003. Assets recorded under capital leases consist of:

(in millions)	2004	2003
Buildings	$ 30	$ 30
Less: Accumulated amortization	(11)	(10)
	$ 19	$ 20

Minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable leases at December 31, 2004, are:

(in millions)	Capital Leases	Operating Leases
2005	$ 2	$ 28
2006	2	24
2007	2	13
2008	2	13
2009	2	12
Thereafter	25	97
	$ 35	$ 187
Less amount representing imputed interest	(16)	
Present value of net minimum lease payments	$ 19	

PEC is the lessor of electric poles, streetlights and other facilities. Minimum rentals receivables under noncancelable leases are $9 million for 2005 and none thereafter. Rents received totaled $32 million, $31 million and $28 million for 2004, 2003 and 2002, respectively.

C. Claims and Uncertainties

OTHER CONTINGENCIES

1. Pursuant to the Nuclear Waste Policy Act of 1982, the predecessors to PEC entered into contracts with the U.S. Department of Energy (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.

DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, PEC 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 (SNF) by failing to accept SNF from various PEC facilities on or before January 31, 1998. Damages due to DOE's breach will likely exceed $100 million. Approximately 60 cases involving the Government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims.

DOE and the PEC parties 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 SNF and high level waste (HLW) by which the Government was contractually obligated to accept contract holders' SNF and/or HLW, 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 that are currently scheduled to occur during 2005. Resolution of these issues in other cases could facilitate agreements by the parties in the PEC lawsuit, or at a minimum, inform the Court of decisions reached by other courts if they remain contested and require resolution in this case. The trial court has continued this stay until June 24, 2005.

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.

In July 2002, Congress passed an override resolution to Nevada's veto of DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nevada. In January 2003, the State of Nevada, Clark County, Nevada, and the City of Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged 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. EPA is currently reworking the standard but has not stated when the work will be complete. 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, DOE announced it would not submit the license application until mid-2005 or later. Also in November 2004, Congressional negotiators approved $577 million for fiscal year 2005 for the Yucca Mountain project, approximately $300 million less than requested by DOE but approximately the same as approved in 2004. The DOE continues to state it plans to begin operation of the repository at Yucca Mountain in 2010. PEC cannot predict the outcome of this matter.

2. In 2001, PEC entered into a contract to purchase coal from Dynegy Marketing and Trade (DMT). After DMT experienced financial difficulties, including credit ratings downgrades by certain credit reporting agencies, PEC requested credit enhancements in accordance with the terms of the coal purchase agreement in July 2002. When DMT did not offer credit enhancements, as required by a provision in the contract, PEC terminated the contract in July 2002.

PEC initiated a lawsuit seeking a declaratory judgment that the termination was lawful. DMT counterclaimed, stating the termination was a breach of contract and an unfair and deceptive trade practice. On March 23, 2004, the United States District Court for the Eastern District of North Carolina ruled that PEC was liable for breach of contract, but ruled against DMT on its unfair and deceptive trade practices claim. On April 6, 2004, the Court entered a judgment against PEC in the amount of approximately $10 million. The Court did not rule on DMT's request under the contract for pending legal costs.

On May 4, 2004, PEC authorized its outside counsel to file a notice of appeal of the April 6, 2004, judgment and on May 7, 2004, the notice of appeal was filed with the United States Court of Appeals for the Fourth Circuit. On June 8, 2004, DMT filed a motion to dismiss the appeal on the ground that PEC's notice of appeal should have been filed on or before May 6, 2004. On June 16, 2004, PEC filed a motion with the trial court requesting an extension of the deadline for the filing of the notice of appeal. By order dated September 10, 2004, the trial court denied the extension request. On September 15, 2004, PEC filed a notice of appeal of the September 10, 2004, order and by order dated September 29, 2004, the appellate court consolidated the first and second appeals. DMT's motion to dismiss the first appeal remains pending.

The consolidated appeal has been fully briefed, and the court of appeals has indicated that it will hear arguments, which tentatively have been scheduled for the week of May 23, 2005.

PEC recorded a liability for the judgment of approximately $10 million and a regulatory asset for the probable recovery through its fuel adjustment clause in the first quarter of 2004. PEC cannot predict the outcome of this matter.

3. On February 1, 2002, PEC filed a complaint with the Surface Transportation Board (STB) challenging the rates charged by Norfolk Southern Railway Company (Norfolk Southern) for coal transportation to certain generating plants. In a decision dated December 23, 2003, the STB found that the rates were unreasonable, awarded reparations and prescribed maximum rates. Both parties petitioned the STB for reconsideration of the December 23, 2003 decision. On October 20, 2004, the STB reconsidered its December 23, 2003 decision and concluded that the rates charged by Norfolk Southern were not unreasonable. Because PEC paid the maximum rates prescribed by the STB in its December 23, 2003 decision for several months during 2004, which were less than the rates ultimately found to be reasonable, the STB ordered PEC to pay to Norfolk Southern the difference between the rate levels plus interest.

PEC subsequently filed a petition with the STB to phase in the new rates over a period of time, and filed a notice of appeal with the U.S. Court of Appeals for the D.C. Circuit. Pursuant to an order issued by the STB on January 6, 2005, the phasing proceeding will proceed on a schedule that appears likely to produce an STB decision before the end of 2005. On January 12, 2005, the STB filed a Motion to Dismiss PEC's appeal on the grounds that its October 20, 2004, order is not "final" until PEC's phasing application has been decided.

As of December 31, 2004, PEC has accrued a liability of $42 million, of which $23 million represents reparations previously remitted to PEC by Norfolk Southern that are now subject to refund. Of the remaining $19 million, $17 million has been recorded as deferred fuel cost on the Consolidated Balance Sheet while the remaining $2 million attributable to wholesale customers has been charged to fuel used in electric generation on the Consolidated Statements of Income.

PEC cannot predict the outcome of this matter.

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

19. SUBSEQUENT EVENT

Cost Management Initiative

On February 28, 2005, as part of a previously announced cost management initiative, the executive officers of Progress Energy approved a workforce restructuring. The restructuring is expected to be completed in September of 2005. In addition to the workforce restructuring, the cost management initiative includes a voluntary enhanced retirement program.

In connection with the cost management initiative, PEC expects to incur one-time pre-tax charges of approximately $55 million. Approximately $10 million of that amount relates to payments for severance benefits, and will be recognized in the first quarter of 2005 and paid over time. The remaining approximately $45 million will be recognized in the second quarter of 2005 and relates primarily to postretirement benefits that will be paid over time to those eligible employees who elect to participate in the voluntary enhanced retirement program. The total cost management initiative charges could change significantly depending upon how many eligible employees elect early retirement under the voluntary enhanced retirement program and the salary, service years and age of such employees.

20. CONSOLIDATED QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data is as follows:

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2004				
Operating revenues	**$ 901**	**$ 862**	**$ 1,014**	**$ 852**
Operating income	**236**	**191**	**317**	**133**
Income before cumulative effect of change in accounting principles	**115**	**96**	**175**	**75**
Net income	**115**	**96**	**175**	**75**
Year ended December 31, 2003				
Operating revenues	$ 929	$ 819	$ 1,012	$ 840
Operating income	256	184	295	234
Income before cumulative effect of change in accounting principles	135	89	158	123
Net income	135	89	158	100

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. Fourth quarter 2004 includes approximately $99 million ($59 million after-tax) more NC Clean Air legislation amortization than the other quarters presented. Fourth quarter 2004 also includes a reduction in depreciation expense of $63 million ($38 million after-tax) resulting from a revised depreciation study due to extended lives at each of PEC's nuclear units (See Note 4A). Fourth quarter 2003 includes impairment charges related to certain investments of $21 million ($13 million after-tax) (See Note 7). Fourth quarter 2003 includes the impact of a cumulative effect for DIG Issue C20 of $38 million ($23 million after-tax) (See Note 13).

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF PROGRESS ENERGY, INC.:

We have audited the consolidated financial statements of Progress Energy, Inc., and its subsidiaries (the Company) as of December 31, 2004 and 2003, and for each of the three years in the period ended December 31, 2004, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, and have issued our reports thereon dated March 7, 2005 (which reports express an unqualified opinion and include an explanatory paragraph concerning the adoption of new accounting principles in 2003); such reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 7, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDER OF CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.:

We have audited the consolidated financial statements of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., and its subsidiaries (PEC) as of December 31, 2004 and 2003, and for each of the three years in the period ended December 31, 2004, and have issued our report thereon dated March 7, 2005 (which expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2003); such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of PEC listed in Item 15. This financial statement schedule is the responsibility of PEC's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 7, 2004

PROGRESS ENERGY, INC.
Schedule II – Valuation and Qualifying Accounts
For the Years Ended
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expenses	Other Additions	Deductions (a)		Balance at End of Period
Valuation and qualifying accounts deducted in the balance sheet from the related assets:						
DECEMBER 31, 2004						
Uncollectible accounts	**$32**	**$17**	**$(4)**	**$(16)**		**$29**
Fossil dismantlement reserve	**143**	**1**	**–**	**–**		**144**
Nuclear refueling outage reserve	**2**	**10**	**–**	**–**		**12**
DECEMBER 31, 2003						
Uncollectible accounts	$39	$24	$4	$(35)		$32
Fossil dismantlement reserve	142	1	–	–		143
Nuclear refueling outage reserve	10	8	–	(16)	(b)	2
DECEMBER 31, 2002						
Uncollectible accounts	$39	$22	$–	$(22)		$39
Fossil dismantlement reserve	141	1	–	–		142
Nuclear refueling outage reserve	–	10	–	–		10

(a) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for uncollectible accounts, such deductions are reduced by recoveries of amounts previously written off.

(b) Represents payments of actual expenditures related to the outages.

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS
Schedule II – Valuation and Qualifying Accounts
For the Years Ended
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expense	Other Additions	Deductions (a)	Balance at End of Period
Valuation and qualifying accounts deducted in the balance sheet from the related assets:					
December 31, 2004					
Uncollectible accounts	**$17**	**$7**	**$(4)**	**$(10)**	**$10**
December 31, 2003					
Uncollectible accounts	$12	$12	$4	$(11)	$17
December 31, 2002					
Uncollectible accounts	$14	$8	$–	$(10)	$12

(a) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for uncollectible accounts, such deductions are reduced by recoveries of amounts previously written off.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Progress Energy, Inc.

DISCLOSURE CONTROLS AND PROCEDURES

Pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934, Progress Energy carried out an evaluation, with the participation of its management, including Progress Energy's Chairman and Chief Executive Officer and Chief Financial Officer, of the effectiveness of Progress Energy's disclosure controls and procedures (as defined under Rule 13a-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, Progress Energy's Chief Executive Officer and Chief Financial Officer concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by Progress Energy in the reports that it files or submits under the Exchange Act, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to Progress Energy's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of Progress Energy's management to establish and maintain adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15(d)-15(f) of the Securities Exchange Act of 1934, as amended. Progress Energy's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America. Internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of Progress Energy; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles in the United States of America; (3) provide reasonable assurance that receipts and expenditures of Progress Energy are being made only in accordance with authorizations of management and directors of Progress Energy; and (4) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Progress Energy's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of Progress Energy's internal control over financial reporting as of December 31, 2004. Management based this assessment on criteria for effective internal control over financial reporting described in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management's assessment included an evaluation of the design of Progress Energy's internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of the Board of Directors.

Based on our assessment, management determined that, as of December 31, 2004, Progress Energy maintained effective internal control over financial reporting.

Management's assessment of the effectiveness of Progress Energy's internal control over financial reporting as of December 31, 2004, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their8 report which is included herein in Item 9A Controls and procedures of this Annual Report on Form 10-K.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING.

There has been no change in Progress Energy's internal control over financial reporting during the quarter ended December 31, 2004, that has materially affected, or is reasonably likely to materially affect its internal control over financial reporting.

The Company notes, however, that as part of the Company's review of internal controls for compliance with Section 404 of the Sarbanes-Oxley Act, the Company will be implementing changes related to capitalization practices for its Energy Delivery business units in PEC and PEF effective January 1, 2005. A review of these practices indicated that in the areas of outage and emergency work, not associated with major storm 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. The changes for 2005 in this area include use of more detailed accounts to segregate capital and expense items, more regular testing of accounting estimates and realignment of certain accounting functions. This matter is also discussed at Footnote 8F to the Progress Energy Consolidated Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF PROGRESS ENERGY, INC.

We have audited management's assessment, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*, that Progress Energy, Inc., and its subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers, or persons performing similar functions, and effected by the Company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2004, of the Company and our report dated March 7, 2005, expressed an unqualified opinion on those consolidated financial statements.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 7, 2005

Progress Energy Carolinas, Inc.

Pursuant to the Securities Exchange Act of 1934, PEC carried out an evaluation, with the participation of its management, including PEC's Chairman and Chief Executive Officer and Chief Financial Officer, of the effectiveness of PEC's disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, PEC's Chief Executive Officer and Chief Financial Officer concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by PEC in the reports that it files or submits under the Exchange Act, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to PEC's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in PEC's internal control over financial reporting during the quarter ended December 31, 2004, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

As noted above, PEC will be implementing changes related to capitalization practices for its Energy Delivery business unit effective January 1, 2005. A review of these practices indicated that in the areas of outage and emergency work, not associated with major storm and allocation of indirect costs, PEC should revise the way that it estimates the amount of capital costs associated with such work. The changes for 2005 in this area include use of more detailed accounts to segregate capital and expense items, more regular testing of accounting estimates and realignment of certain accounting functions. This matter is also discussed in Note 6E to the PEC Consolidated Financial Statements.

ITEM 9B. OTHER INFORMATION

In March 2005, Progress Energy, Inc.'s five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65% to 68% in anticipation of the potential impacts of proposed accounting rules for uncertain tax positions.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

a) Information on Progress Energy, Inc.'s directors is set forth in the Progress Energy 2004 definitive proxy statement dated March 31, 2005, and incorporated by reference herein. Information on PEC's directors is set forth in the PEC 2004 definitive proxy statement dated March 31, 2005, and incorporated by reference herein.

b) Information on both Progress Energy's and PEC's executive officers is set forth in PART I and incorporated by reference herein.

c) The Company has adopted a Code of Ethics that applies to all of its employees, including its Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and Controller (or persons performing similar functions). The Company's Board of Directors has adopted the Company's Code of Ethics as its own standard. Board members, Company officers and Company employees certify their compliance with the Code of Ethics on an annual basis. The Company's Code of Ethics is posted on its Internet Web site and can be accessed at www.progress-energy.com and is available in print to any shareholder upon request by writing to Progress Energy, Inc.

The Company intends to satisfy the disclosure requirement under Item 10 of Form 8-K relating to amendments to or waivers from any provision of the Code of Ethics applicable to the Company's CEO, CFO, CAO and Controller by posting such information on its Internet Web site, www.progress-energy.com.

d) The Board of Directors has determined that David L. Burner and Carlos A. Saladrigas are the "Audit Committee Financial Experts," as that term is defined in the rules promulgated by the Securities and Exchange Commission pursuant to the Sarbanes-Oxley Act of 2002, and have designated them as such. Both Mr. Burner and Mr. Saladrigas are "independent," as that term is defined in the general independence standards of the New York Stock Exchange listing standards.

e) The following are available on the Company's Web site and in print at no cost:
- Audit Committee Charter
- Corporate Governance Committee Charter
- Organization and Compensation Committee Charter
- Corporate Governance Guidelines

ITEM 11. EXECUTIVE COMPENSATION

Information on Progress Energy's executive compensation is set forth in the Progress Energy 2004 definitive proxy statement dated March 31, 2005, and incorporated by reference herein. Information on PEC's executive compensation is set forth in the PEC 2004 definitive proxy statement dated March 31, 2005, and incorporated by reference herein.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

a) Information regarding any person Progress Energy knows to be the beneficial owner of more than five (5%) percent of any class of its voting securities is set forth in its 2004 definitive proxy statement, dated March 31, 2005, and incorporated herein by reference.

Information regarding any person PEC knows to be the beneficial owner of more than 5% of any class of its voting securities is set forth in its 2004 definitive proxy statement, dated March 31, 2005, and incorporated herein by reference.

b) Information on security ownership of the Progress Energy's and PEC's management is set forth in the Progress Energy and PEC 2004 definitive proxy statements dated March 31, 2005, and incorporated by reference herein.

c) Information on the equity compensation plans of Progress Energy is set forth under the heading "Equity Compensation Plan Information" in the Progress Energy 2004 definitive proxy statement dated March 31, 2005, and incorporated by reference herein.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information on certain relationships and related transactions is set forth in the Progress Energy and PEC 2004 definitive proxy statements dated March 31, 2005, and incorporated by reference herein.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information regarding principal accountant fees and services is set forth in the Progress Energy and PEC 2004 definitive proxy statements dated March 31, 2005, and incorporated by reference herein.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

a) The following documents are filed as part of the report:

1. Consolidated Financial Statements Filed:
   See ITEM 8 – Consolidated Financial Statements and Supplementary Data

2. Consolidated Financial Statement Schedules Filed:
   See ITEM 8 – Consolidated Financial Statements and Supplementary Data

3. Exhibits Filed:
   See EXHIBIT INDEX

PROGRESS ENERGY, INC. RISK FACTORS

In this section, unless the context indicates otherwise, references to "our," "we," "us" or similar terms refer to Progress Energy, Inc. and its consolidated subsidiaries. Investing in our securities involves risks, including the risks described below, that could affect the energy industry, as well as us and our business. Most of the business information as well as the financial and operational data contained in our risk factors are updated periodically in the reports we file with the SEC. Although we have tried to discuss key factors, please be aware that other risks may prove to be important in the future. New risks may emerge at any time and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Before purchasing our securities, you should carefully consider the following risks and the other information in this Annual Report, as well as the documents we file with the SEC from time to time. Each of the risks described below could result in a decrease in the value of our securities and your investment therein.

Risks Related to the Energy Industry

We are subject to fluid and complex government regulations that may have a negative impact on our business, financial condition and results of operations.

We are subject to comprehensive regulation by several federal, state and local regulatory agencies, which significantly influence our operating environment and may affect our ability to recover costs from utility customers. We are subject to regulatory oversight with respect to, among other things, rates and service for electric energy sold at retail, retail service territory and issuances of securities. In addition our operating utilities are subject to regulation with respect to transmission and sales of wholesale power, accounting and certain other matters. We are also required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

The 108th Congress spent much of 2004 working on a comprehensive energy bill. While that legislation passed the House, the Senate failed to pass the legislation in 2004. There will probably be an effort to resurrect the legislation in 2005. The legislation would have further clarified the Federal Energy Regulatory Commission's ("FERC") role with respect to Standard Market Design and mandatory Regional Transmission Organizations ("RTOs") and would have repealed the Public Utility Holding Company Act of 1935 ("PUHCA"). The Company cannot predict the outcome or impact of the proposed or any future energy bill.

FERC, the U.S. Nuclear Regulatory Commission ("NRC"), the U.S. Environmental Protection Agency ("EPA"), the North Carolina Utilities Commission ("NCUC"), the Florida Public Service Commission ("FPSC"), and the Public Service Commission of South Carolina ("SCPSC") regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. Our system is also subject to the jurisdiction of the SEC under PUHCA. The rules and regulations promulgated under PUHCA impose a number of restrictions on the operations of registered utility holding companies and their subsidiaries. These restrictions include a requirement that, subject to a number of exceptions, the SEC approve in advance securities issuances, acquisitions and dispositions of utility assets or of securities of utility companies, and acquisitions of other businesses. PUHCA also generally limits the operations of a registered holding company like ours to a single integrated public utility system, plus additional energy-related businesses. Furthermore, PUHCA rules require that transactions between affiliated companies in a registered holding company system be performed at cost, with limited exceptions.

We are unable to predict the impact on our business and operating results from future regulatory activities of these federal, state and local agencies. Changes in regulations or the imposition of additional regulations could have a negative impact on our business, financial condition and results of operations.

We are subject to numerous environmental laws and regulations that require significant capital expenditures, increase our cost of operations, and which may impact or limit our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. We cannot predict the outcome (financial or operational) of any related litigation that may arise.

In addition, we may be a responsible party for environmental clean up at sites identified by a regulatory body. We cannot predict with certainty the amount or timing of all future expenditures related to environmental matters because of the difficulty of estimating clean up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all PRPs.

Our compliance with environmental regulations requires significant capital expenditures that impact our financial condition. For example, in June 2002, legislation was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide ("NOx") and sulfur dioxide ("SO_2") from coal-fired power plants. We expect the capital costs required to meet these emission targets will total approximately $895 million by 2013. Over the next three years, we expect to incur approximately $510 million of total capital costs associated with this legislation.

Congress currently considering further legislation that would require reductions in air emissions of NOx, SO_2, carbon dioxide and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multi-pollutant approach to air pollution control could involve significant capital costs which could be material to our consolidated financial position or results of operations. However, the Company cannot predict the outcome, costs or impact of this matter. In December 2003, the EPA released its proposed Interstate Air Quality Rule, currently referred to as the Clean Air Interstate Rule (CAIR). The EPA's proposal requires 29 jurisdictions, including North Carolina, South Carolina, Georgia and Florida, to reduce NOx and SO_2 emissions in order to attain preset state NOx and SO_2 emissions levels. The rule is expected to become final in March 2005. While the air quality controls already installed and currently planned for installation to comply with the NC Clean Air legislation will reduce the costs required to meet the CAIR requirements for the our North Carolina units, additional compliance costs will be determined once the rule is finalized. 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 thirteen 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. The EPA has agreed to make a determination on the petition by August 1, 2005. The Company cannot predict the outcome or costs associated with the matter.

See additional discussion of these environmental matters in Note 22 to the Progress Energy Consolidated Financial Statements.

We cannot assure you that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our results of operations.

The uncertain outcome regarding the timing, creation and structure of regional transmission organizations, or RTOs, may materially impact our results of operations, cash flows or financial condition.

Congress, FERC, and the state utility regulators have paid significant attention in recent years to transmission issues, including the possibility of regional transmission organizations. While these deliberations have not yet resulted in significant changes to our utilities' transmission operations, they cast uncertainty over those operations, which constitute a material portion of our assets.

For the last several years, the FERC has supported independent RTOs and has indicated a belief that it has the authority to order transmission-owning utilities to transfer operational control of their transmission assets to such RTOs. Many state regulators, including most regulators in the Southeast, have expressed skepticism over the potential benefits of RTOs and generally disagree with the FERC's interpretation of its authority to mandate RTOs. In July 2002, the FERC issued its Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR). In its current form, SMD NOPR could materially alter the manner in which transmission and generation services are provided and paid for, and includes provisions for mandatory RTOs and the FERC's assertion of jurisdiction over certain aspects of retail service. The Company cannot predict the outcome or timing of any final rules or the effect that they may have on the GridSouth and GridFlorida proceedings currently ongoing before the FERC.

At the state level, significant uncertainty exists with respect to what action, if any, the NCUC or FPSC will ultimately take. The Company has $33 million and $4 million invested in GridSouth and GridFlorida, respectively, related to startup costs at December 31, 2004. These amounts are included as a regulatory asset at December 31, 2004. The Company expects to recover these startup costs in conjunction with the GridSouth and GridFlorida original structures or in conjunction with any alternate combined transmission structures that may be required. Furthermore, the SMD NOPR presents several uncertainties, including what percentage of our investments in GridSouth and GridFlorida will be recovered, how the elimination of transmission charges, as proposed in the SMD NOPR, will impact us, and what amount of capital expenditures will be necessary to create a new wholesale market.

The actual structure of GridSouth, GridFlorida or any alternative combined transmission structure, as well as the date it may become operational, depends upon the resolution of all regulatory approvals and technical issues. Given the regulatory uncertainty of the ultimate timing, structure and operations of GridSouth, GridFlorida or an alternate combined transmission structure, we cannot predict whether they will be created, or whether they will have any material adverse effect on our future consolidated results of operations, cash flows or financial condition.

Since weather conditions directly influence the demand for and cost of providing electricity, our results of operations, financial condition, cash flows and ability to pay dividends on our common stock can fluctuate on a seasonal or quarterly basis and can be negatively affected by changes in weather conditions and severe weather.

Our results of operations, financial condition, cash flows and ability to pay dividends on our common stock may be affected by changing weather conditions. Weather conditions in our service territories, primarily North Carolina, South Carolina, and Florida, directly influence the demand for electricity affect the price of energy commodities necessary to provide electricity to our customers and energy commodities that our nonregulated businesses sell.

Electric power demand is generally a seasonal business. In many parts of the country, demand for power and market prices peak during the hot summer months. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the nature and location of facilities we acquire and the terms of power sale contracts into which we enter. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. While we believe that our North Carolina, South Carolina, and Florida markets complement each other during normal seasonal fluctuations, unusually mild weather could diminish our results of operations and harm our financial condition.

Furthermore, severe weather in these states, such as hurricanes, tornadoes, severe thunderstorms, snow and ice storms, can be destructive, causing outages, downed power lines and property damage, requiring us to incur additional and unexpected expenses and causing us to lose generating revenues. For example, during the third quarter of 2004, four hurricanes hit our service territories, resulting in storm costs of approximately $398 million. In addition, these storm costs reduced our projected 2004 regular federal income tax liability, and consequently, our ability to benefit from the tax credits generated from our synthetic fuel operations.

Our ability to recover significant costs resulting from severe weather events is subject to regulatory oversight and the timing and amount of any such recovery is uncertain and may impact our financial conditions.

During the third quarter of 2004, four hurricanes struck significant portions of our service territories, most significantly impacting PEF's territory. The total estimated restoration cost of these storms is $398 million. PEC incurred restoration costs of $13 million, of which $12 million was charged to operation and maintenance expense and $1 million was charged to capital expenditures. PEF had estimated total costs of $385 million, of which $47 million was charged to capital expenditures, and $338 million was charged to the storm damage reserve pursuant to a regulatory order.

Under a regulatory order, PEF maintains a storm damage reserve account for major storms. With respect to storm costs in excess of the storm damage reserve account, PEF may seek recover from retail ratepayers. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail ratepayers over a two-year period. Given that not all invoices have been received as of December 31, 2004, it is PEF's position that its petition presents a fair projection of total cost and does not need to be updated at this time. PEF will update its request upon receipt and audit of all actual charges incurred. Storm reserve costs of $13 million are attributable to wholesale customers and such costs may be amortized consistent with recovery of such amounts in wholesale rates. The timing of any FPSC decision and ultimate amount recovered is uncertain at this time.

PEC is not required to maintain a storm damage reserve account and does not have an on-going regulatory mechanism to recover storm costs and; therefore, hurricane restoration costs recorded in the third quarter of 2004 were charged to operations and maintenance expenses or capital expenditures based on the nature of the work performed. In connection with other storms, PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over a five-year period. PEC did not seek recovery of 2004 storm costs from the NCUC.

While we believe that we are legally entitled to recover these costs, if we cannot recover these costs, or costs associated with future significant weather events, in a timely manner, or in an amount sufficient to cover our actual costs, our financial conditions and results of operations could be materially and adversely impacted.

Our revenues, operating results and financial condition may fluctuate with the economy and its corresponding impact on our commercial and industrial customers as well as the demand and competitive state of the wholesale market.

Our business is impacted by fluctuations in the macroeconomy. For the year ended December 31, 2004, commercial and industrial customers represented approximately 37% of our total electric revenues. As a result, changes in the macroeconomy can have negative impacts on our revenues. As our commercial and industrial customers experience economic hardships, our revenues can be negatively impacted. In recent years, in North and South Carolina, sales to industrial customers have been affected by downturns in the textile and chemical industries.

For the year ended December 31, 2004, 12% of our total electric revenues were from wholesale sales. Wholesale revenues fluctuate with regional demand, fuel prices, and contracted capacity. Our wholesale profitability is dependent upon our ability to renew or replace expiring wholesale contracts on favorable terms. During 2004, wholesale revenues decreased from expiring contracts being renegotiated by PEC at less favorable terms due to slightly depressed markets and from increased competition in the wholesale markets served by PEC. If this trend market environment persists, we may experience further declines in our wholesale revenues.

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 believes it would experience in passing one of the interim screens, on August 12, 2004, PEC notified the FERC that it would revise its Market-based Rate tariff to restrict it to sales outside PEC's control area and file a new cost-based tariff for sales within PEC's control area that incorporates the FERC's default cost-based rate methodologies for sales of one-year basis. We anticipate making this filing the first quarter of 2005. We cannot predict what impact PEC's requirement to implement cost-based tariffs will have on our future financial condition, results of operations or cash flows.

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect the financial condition, results of operations or cash flows of us and our utilities' businesses.

Increased competition resulting from deregulation or restructuring efforts could have a significant adverse financial impact on us and our utility subsidiaries and consequently on our results of operations and cash flows. Increased competition could also result in increased pressure to lower costs, including the cost of electricity. Retail competition and the unbundling of regulated energy and gas service could have a significant adverse financial impact on us and our subsidiaries due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Because we have not previously operated in a competitive retail environment, we cannot predict the extent and timing of entry by additional competitors into the electric markets. Due to several factors, however, there currently is little discussion of any movement toward deregulation in North Carolina, South Carolina and Florida. We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our financial condition, results of operations or cash flows.

Increased commodity prices may adversely affect the financial condition, results of operations or cash flows of us and our utilities' businesses.

The Company is exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related products marketed and purchased as a result of its ownership of energy-related assets. While each state commission allows electric utilities to recover certain of these costs through various cost recovery clauses, there is the potential that all or a portion of these future costs could be deemed imprudent by the respective commissions. There is also a delay between the timing of when these costs are incurred by the utilities and when these costs are recovered from the ratepayers, which can adversely impact the cash flow of the Company and its subsidiaries.

Prices for SO_2 emission allowance credits under the EPA's emission trading program increased significantly during 2004. While SO_2 allowances are eligible for annual recovery in the Company's jurisdictions in Florida and South Carolina, no such annual recovery exists in North Carolina. Future increases in the price of SO_2 allowances could have a significant adverse financial impact on us and PEC and consequently on our results of operations and cash flows.

Risks Related to Us and Our Business

As a holding company, we are dependent on upstream cash flows from our subsidiaries, primarily our regulated utilities. As a result, our ability to meet our ongoing and future financial obligations and to pay dividends on our common stock is primarily dependent on the earnings and cash flows of our operating subsidiaries and their ability to pay upstream dividends or to repay funds to us.

We are a holding company. As such, we have no operations of our own. Our ability to meet our financial obligations associated with interest charges on $4.3 billion of holding company debt and to pay dividends on our common stock at the current rate is primarily dependent on the earnings and cash flows of our operating subsidiaries, primarily our regulated utilities, and the ability of our subsidiaries to pay upstream dividends or to repay funds to us. Prior to funding us, our subsidiaries have financial obligations that must be satisfied, including among others, debt service, dividends and obligations to trade creditors. For the year ending December 31, 2004, approximately 100% of the Company's cash from operations was provided by its utility subsidiaries. Other sources of cash include the issuance of equity, short-term debt and intercompany charges for capital costs.

The rates that our utility subsidiaries may charge retail customers for electric power are subject to the authority of state regulators. Accordingly, our profit margins could be adversely affected if we or our utility subsidiaries do not control operating costs.

The NCUC, the SCPSC and the FPSC each exercises regulatory authority for review and approval of the retail electric power rates charged within its respective state. State regulators may not allow our utility subsidiaries to increase retail rates in the manner or to the extent requested by those subsidiaries. State regulators may also seek to reduce retail rates. For example, in March 2002, PEF entered into a Stipulation and Settlement Agreement (the

"Agreement") that required PEF, among other things, to reduce its retail rates and to operate under a revenue sharing plan through 2005 which provides for possible rate refunds to its retail customers. The Agreement will also require increased capital expenditures for PEF's Commitment to Excellence program. However, if PEF's base rate earnings fall below a 10% return on equity, PEF may petition the FPSC to amend its base rates. As discussed below, in January 2005, PEF petitioned the FPSC for an increase in its retail base rates.

Additionally, under the NC Clean Air legislation in North Carolina, passed in 2002, PEC's base retail rates were frozen for five years unless there are significant cost changes due to governmental action, significant expenditures due to force majeure or other extraordinary events beyond the control of PEC, and PEC has agreed not to seek a base retail electric rate increase in South Carolina through 2005. The same legislation required a significant increase in capital expenditures over the next several years for clean air improvements. The cash costs incurred by our utility subsidiaries are generally not subject to being fixed or reduced by state regulators. Our utility subsidiaries will also require dedicated capital expenditures. Thus, our ability to maintain our profit margins depends upon stable demand for electricity and our efforts to manage our costs.

If the FPSC does not approve our request for increased base rates, we will be faced with a significantly increased cost structure that will not be adequately covered by our base rates and, as a result, our results of operations, financial condition and ability to pay dividends could be materially and adversely impacted.

In January 2005, in anticipation of the expiration of the Agreement approved by the FPSC in 2002 to conclude PEF's then-pending rate case, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2006. In its notice, PEF requested the FPSC to approve calendar year 2006 as the projected test period for setting new base rates. We have faced significant cost increases over the past decade and expect our operational costs to continue to increase. These costs include the costs associated with (i) completion of our Hines 3 generation facility, (ii) extraordinary hurricane damage costs, including approximately $50 million in capital costs which are not expected to be directly recoverable, (iii) our need to replenish our depleted storm reserve or adjust the annual accrual by approximately $50 million annually in light of recent history on a going-forward basis, and (iv) the expected infrastructure investment necessary to meet high customer expectations, coupled with the demands placed on our strong customer growth. In addition, significant additional costs include increased depreciation and fossil dismantlement expenses in excess of $70 million when the provisions of the Agreement addressing these expenses expire at the end of this year. We also face the prospect of significant compliance costs from participation in the GridFlorida regional transmission organization pursuant to FERC's transmission independence initiative and the FPSC's related directive. Finally, as is the case with most companies in our industry, we will continue to experience the pervasive upward pressure of inflation on costs in general, especially the rapidly increasing costs of employee healthcare and other benefit programs.

Under the Agreement, our base rates are at a level that existed in 1983; by contrast, the Consumer Price Index has increased just over 90% since then. If the FPSC does not approve our request for increased base rates, we will be faced with a significantly increased cost structure that will not be covered by our base rates. Additionally, as discussed below, the credit ratings of PEF may be negatively impacted by the outcome of the rate case. As a result, our results of operations, financial condition and ability to pay dividends could be materially and adversely impacted.

There are inherent potential risks in the operation of nuclear facilities, including environmental, health, regulatory, terrorism, and financial risks that could result in fines or the shutdown of our nuclear units, which may present potential exposures in excess of our insurance coverage.

We own and operate five nuclear units through our subsidiaries, PEC (four units) and PEF (one unit), that represent approximately 4,286 MW, or 18%, of our generation capacity for the year ended December 31, 2004. Our nuclear facilities are subject to environmental, health and financial risks such as the ability to dispose of spent nuclear fuel, the ability to maintain adequate capital reserves for decommissioning, potential liabilities arising out of the operation of these facilities, and the costs of securing the facilities against possible terrorist attacks. We maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that damages could exceed the amount of our insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or to shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could require us to make substantial capital expenditures at our nuclear plants. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could materially and adversely affect our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

From time to time, our facilities require licenses that need to be renewed or extended in order to continue operating. We do not anticipate any problems renewing these licenses as required. However, as a result of potential terrorist threats and increased public scrutiny of utilities, the licensing process could result in increased licensing or compliance costs that are difficult or impossible to predict.

Our financial performance depends on the successful operation of electric generating facilities by our subsidiaries and our ability to deliver electricity to our customers.

Operating electric generating facilities and delivery systems involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- fuel supply interruptions; and
- catastrophic events such as hurricanes, fires, earthquakes, explosions, floods, terrorist attacks or other similar occurrences.

A decrease or elimination of revenues generated from our subsidiaries' electric generating facilities and electricity delivery systems or an increase in the cost of operating the facilities could have an adverse effect on our business and results of operations.

Our business is dependent on our ability to successfully access capital markets. Our inability to access capital may limit our ability to execute our business plan, or pursue improvements and make acquisitions that we may otherwise rely on for future growth.

We rely on access to both short-term and long-term capital markets, and lines of credit with commercial banks as a significant source of liquidity for capital requirements not satisfied by the cash flow from our operations. If we are not able to access these sources of liquidity, our ability to implement our strategy will be adversely affected. We believe that we will maintain sufficient access to these financial markets based upon current credit ratings. However, certain market disruptions or a downgrade of our credit rating to below investment grade would increase our cost of borrowing and may adversely affect our ability to access one or more financial markets. Market disruptions create a unique uncertainty as they typically result from factors beyond are control. Such market disruptions could include:

- an economic downturn;
- the bankruptcy of an unrelated energy company;
- capital market conditions generally;
- allegations of corporate scandal at unrelated companies;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on our facilities or unrelated energy companies; or
- the overall health of the utility industry.

In addition, we believe that these market disruptions, unrelated to our business, could result in a ratings downgrade and, correspondingly, increase our cost of capital. Additional risks regarding the impact of a ratings downgrade are discussed below. Restrictions on our ability to access financial markets may affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth.

Increases in our leverage could adversely affect our competitive position, business planning and flexibility, financial condition, ability to service our debt obligations and to pay dividends on our common stock, and ability to access capital on favorable terms.

Our cash requirements arise primarily from the capital-intensive nature of our electric utilities. In addition to operating cash flows, we rely heavily on our commercial paper and long-term debt. At December 31, 2004, commercial paper and bank borrowings and long-term debt balances for Progress Energy and its subsidiaries were as follows (in millions):

Company	Outstanding Commercial Paper and Bank Borrowings	Total Long-Term Debt, Net
Progress Energy, unconsolidated (a)	$ 170	$ 4,449
PEC	221	2,750
PEF	293	1,912
Other Subsidiaries	–	410 (b)
Progress Energy, consolidated	$ 684	$ 9,521 (c)

(a) Represents solely the outstanding indebtedness of the holding company.
(b) Includes the following subsidiaries: Florida Progress Funding Corporation ($270 million) and Progress Capital Holdings, Inc. ($140 million).
(c) Net of current portion, which at December 31, 2004, was $349 million on a consolidated basis.

At December 31, 2004, Progress Energy and its subsidiaries have an aggregate of five committed credit lines that support our commercial paper programs totaling $1.98 billion. While our financial policy precludes us from issuing commercial paper in excess of our credit lines, at December 31, 2004, we had an outstanding commercial paper balance and letters of credit of $574 million, leaving an additional $931 million available for future borrowing under our credit lines.

On January 31, 2005 Progress Energy, Inc. entered into a new $600 million revolving credit agreement, which expires December 30, 2005. This facility was added to provide additional liquidity during 2005 due in part to storm restoration costs incurred in Florida during 2004. The Credit Agreement includes a defined maximum total debt to total capital ratio of 65% and a minimum interest coverage ratio of 2.5 to 1. The Credit Agreement also contains various cross-default and other acceleration provisions. On February 4, 2005, $300 million was drawn under the new facility to reduce commercial paper and bank loans outstanding.

Our credit lines impose various limitations that could impact our liquidity. Our credit facilities include defined maximum total debt to total capital (leverage) ratios and minimum coverage ratios. Under the credit facilities, indebtedness includes certain letters of credit and guarantees which are not recorded on our consolidated Balance Sheets. At December 31, 2004, the required and actual ratios were as follows:

	Leverage Ratios		Coverage Ratios	
Company	Maximum Ratio	Actual Ratio	Minimum Ratio	Actual Ratio
Progress Energy	65%	60.7%	2.5:1	4.00:1
PEC	65%	52.3%	n/a	n/a
PEF	65%	50.8%	3.0:1	7.93:1

In March 2005, Progress Energy, Inc.'s five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65% to 68% in connection with the potential accounting rules for uncertain tax positions. See Notes 2 and 23E to the Progress Energy Consolidated Financial Statements.

In the event our capital structure changes such that we approach the permitted ratios, our access to capital and additional liquidity could decrease. Furthermore, the credit lines of PEC and PEF each include provisions under which lenders could refuse to advance funds to each company under their respective credit lines in the event of a material adverse change in the respective company's financial condition. For Progress Energy's credit lines, loan draws for the payment of maturing commercial paper are excluded from this provision. A limitation in our liquidity could have a material adverse impact on our business strategy and our ongoing financing needs.

Our indebtedness also includes several cross-default provisions which could significantly impact our financial condition. Progress Energy's, PEC's and PEF's credit lines each include cross-default provisions for defaults of indebtedness in excess of $10 million. Under these provisions, if the applicable borrower or certain subsidiaries fail to pay various debt obligations in excess of $10 million, the lenders could accelerate payment of any outstanding borrowings and terminate their commitments to the credit facility. Progress Energy's cross default provisions only apply to defaults of indebtedness by Progress Energy and its significant subsidiaries (i.e., PEC, Florida Progress, PEF, PCH and Progress Fuels). PEC's and PEF's cross-default provisions only apply to defaults of indebtedness by PEC and PEF and their subsidiaries, respectively, not other affiliates of PEC and PEF.

Additionally, certain of Progress Energy's long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of $25 million; these provisions only apply to other obligations of Progress Energy, not its subsidiaries. In the event that either of these cross-default provisions is triggered, the debt holders could accelerate payment of approximately $4.3 billion in long-term debt. Any such acceleration would cause a material adverse change in the respective company's financial condition. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

Changes in economic conditions could result in higher interest rates, which would increase our interest expense on our floating rate debt and reduce funds available to us for our current plans. Additionally, an increase in our leverage could adversely affect us by:

- increasing the cost of future debt financing;
- impacting our ability to pay dividends on our common stock at the current rate;
- making it more difficult for us to satisfy our existing financial obligations;
- limiting our ability to obtain additional financing, if we need it, for working capital, acquisitions, debt service requirements or other purposes;
- increasing our vulnerability to adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete;
- placing us at a competitive disadvantage compared to our competitors who have less debt; and
- causing a downgrade in our credit ratings.

Any reduction in our credit ratings which would cause us to be rated below investment grade would likely increase our borrowing costs, limit our access to additional capital and require posting of collateral, all of which could materially and adversely affect our business, results of operations and financial condition.

On February 11, 2005, Moody's Investors Service (Moody's) credit rating agency announced that it lowered the ratings of Progress Energy Florida, Progress Capital Holdings and FPC Capital Trust I and changed their rating outlooks to stable from negative. Moody's affirmed the ratings of Progress Energy and PEC. The rating outlooks continue to be stable at PEC and negative at Progress Energy. Moody's stated that it took this action primarily due to declining credit metrics, higher O&M costs, uncertainty regarding the timing of hurricane cost recovery, regulatory risks associated with the upcoming rate case in Florida and ongoing capital requirements to meet Florida's growing demand.

In October 2004, Moody's changed its outlook for Progress Energy from stable to negative and placed the ratings of PEF under review for possible downgrade. PEC's ratings were affirmed. Accordingly, Progress Energy's senior unsecured debt is rated "Baa2," (negative outlook) by Moody's. Moody's cited weak financial ratios relative to its current ratings category, rising O&M, pension, benefit and insurance costs, and delays in executing its deleveraging plan as the primary reasons for the change in outlook. With respect to PEF, Moody's cited declining cash flows and rising leverage over the last several years, expected funding needs for large capital expenditure programs, risks regarding its upcoming 2005 rate case and the timing of hurricane cost recovery as the primary reason for placing the PEF's credit ratings under review.

In October 2004, S&P also changed Progress Energy's outlook from stable to negative. S&P cited uncertainties regarding the timing of recovery of hurricane costs, the Company's debt reduction plans, and the IRS audit of our Earthco synthetic fuel facilities as the primary reasons for the change in outlook. In addition, for similar reasons, S&P reduced the short-term debt rating of Progress Energy, PEC and PEF to "A-3" from "A-2". Progress Energy's senior unsecured debt is rated "BBB-" by S&P. PEC's senior unsecured debt has been assigned a rating by S&P of "BBB" (negative outlook) and by Moody's of "Baa1" (stable outlook). PEF's senior unsecured debt has been assigned a rating by S&P of "BBB" (negative outlook) and by Moody's of "A-3" (stable outlook).

The forgoing ratings actions by S&P and Moody's do not trigger any debt or collateral guarantee requirement, however our short-term cost of capital has increased by between 25 to 87.5 basis points. However, the ratings currently assigned to Progress Energy's, senior unsecured debt is S&P's lowest investment grade ratings category and has a negative outlook. Accordingly, any further downgrade by S&P of Progress Energy's senior unsecured rating will result in a noninvestment grade rating and will trigger debt and collateral guarantee requirements (as described below), and may have a material adverse impact on our cost of capital, results of operations and liquidity.

While the Company's long-term target credit ratings for each entity are above the minimum investment grade ranking, we cannot assure you that any of Progress Energy's current ratings, or those of PEC and PEF, will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade could increase our borrowing costs and may adversely affect our access to capital, which could negatively impact our financial results. Further, we may be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease. Although we would have access to liquidity under our committed and uncommitted credit lines, if our short-term rating were to fall below A-3 or P-2, the current ratings assigned by S&P and Moody's, respectively, our access to the commercial paper market would be significantly limited. We note that the ratings from credit agencies are not recommendations to buy, sell or hold our securities or those of PEC or PEF and that each rating should be evaluated independently of any other rating.

Our energy marketing business relies on Progress Energy's investment grade ratings to stand behind transactions in that business. At December 31, 2004, Progress Energy has issued guarantees with a notional amount of approximately $809 million to support CCO's energy marketing businesses. Based upon the amount of trading positions outstanding at December 31, 2004, if Progress Energy's ratings were to decline below investment grade by either S&P or Moody's (i.e., below "BBB-" at S&P or below "Baa3" at Moody's), we would have to deposit cash or provide letters of credit or other cash collateral for approximately $450 million for the benefit of our counterparties. Additionally, the power supply agreement with Jackson Electric Membership Corporation that PVI acquires from Williams Energy Marketing and Trading Company includes a performance guarantee that Progress Energy assumed. In the event that Progress Energy's credit ratings fall below investment grade, Progress Energy will be required to provide additional security for its guarantee in form and amount acceptable to Jackson, but not to exceed the coverage amount. The coverage amount at the inception of PVI's power sale to Jackson is $285 million and will decline over the life of the transaction. At December 31, 2004, the coverage amount is $275 million. These collateral requirements could adversely affect our profitability on energy trading and marketing transactions and limit our overall liquidity. In addition, if we are unable to fund or otherwise satisfy these guarantee obligations our financial condition and liquidity would be further impacted in a material adverse manner.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

We use derivatives, including futures, forwards and swaps, to manage our commodity and financial market risks. In the future, we could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

We could incur a significant tax liability, and our results of operations and cash flows may be materially and adversely affected if the Internal Revenue Service denies or otherwise makes unusable the Section 29 tax credits related to our coal and synthetic fuels businesses.

Synthetic Fuel Risks Associated With the IRS Audit

Through our Fuels segment, we produce coal-based solid synthetic fuel. The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 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. All of our synthetic fuel facilities have received favorable private letter rulings (PLRs) from the Internal Revenue Service (IRS) with respect to their synthetic fuel operations, although these PLR's do not make any "placed-in-service" determinations. These tax credits are subject to review by the IRS.

In July 2004, we were notified that the IRS field auditors anticipated taking an adverse position regarding the placed-in-service date of the Company's four Earthco synthetic fuel facilities. Due to the auditors' position, the IRS decided to exercise its right to withdraw from the PFA program with us. In October 2004, we received the IRS field auditors' report concluding that the Earthco facilities had not been placed in service before July 1, 1998, and that the tax credits generated by those facilities should be disallowed. We intend to contest the field auditors' findings and their proposed disallowance of the tax credits. We believe that the appeals process, including proceedings before the IRS's National Office, could take up to two years to complete. We cannot control the actual timing of resolution and cannot predict the outcome of this matter.

Through December 31, 2004, on a consolidated basis, we have or carried forward approximately $1.0 billion of tax credits generated by the Earthco facilities. If these credits were disallowed, our one-time exposure for cash tax payments would be $294 million (excluding interest), and earnings and equity would be reduced by approximately $1.0 billion, excluding interest. If we were required to reverse approximately $1.0 billion of tax credits and pay $294 million for taxes our financial condition, results of operations and liquidity would be materially and adversely impacted.

Progress Energy's amended $1.13 billion credit facility includes a covenant which limits the maximum debt-to-total capital ratio to 68%. This ratio includes other forms of indebtedness such as guarantees issued by Progress Energy, letters of credit and capital leases. As of December 31, 2004, Progress Energy's debt-to-total capital ratio was 60.7% based on the credit agreement definition for this ratio. The impact on this ratio of reversing approximately $1.0 billion of tax credits and paying $294 million for taxes would be to increase the ratio to 65.7%.

We believe that we operate in conformity with all the necessary requirements to be allowed such credits under Section 29. The current Section 29 tax credit program will expire at the end of 2007. With respect to any IRS review or audit of our synthetic fuel operations, if we fail to prevail through the administrative or legal process, there could be a significant tax liability owed for previously taken Section 29 credits or we could lose our ability to claim future tax credits that we might otherwise be able to benefit from both of which would significantly impact earnings and cash flows.

In October 2003, the United States Senate Permanent Subcommittee on Investigations began a general investigation concerning synthetic fuel tax credits claimed under Section 29 of the Internal Revenue Code. The investigation generally relates to the utilization of the tax 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. We are providing information in connection with this investigation as requested.

Synthetic Fuel Risks Associated with Pending Accounting Rules for Uncertain Tax Positions

In July 2004, the Financial Accounting Standards Board ("FASB") stated that it plans to issue an exposure draft of a proposed interpretation of SFAS No. 109, "Accounting for Income Taxes," that would address the accounting for uncertain tax positions. The FASB has indicated that the interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the financial statements. The exposure draft is expected to be issued in the first quarter of 2005. Under the prevailing sentiment, the IRS field auditors' recommendation that the Earthco tax credits be disallowed would make it difficult to conclude that the tax benefits from the Earthco facilities are probable of being sustained. Accordingly, it is likely we would not be able to record the benefit of the Earthco tax credits on our financial statements. This could require us to create a reserve up to $1.0 billion until the IRS issue is resolved, which would immediately increase our debt to capitalization ratios. The Company cannot predict what actions the FASB will take or how any such actions might ultimately affect the Company's financial position or results of operations, but such changes could have a material impact on the Company's evaluation and recognition of Section 29 tax credits, which, in turn, may have a material impact on our results of operations and financial condition.

Synthetic Fuel Risks Associated With Fluctuations in the Company's Regular Income Tax Liability

The Company's synthetic fuel production levels and the amount of tax credits it can claim each year are a function of the Company's projected consolidated regular federal income tax liability. Any conditions that negatively impact the Company's tax liability, such as weather, could also diminish the Company's ability to utilize credits, including those previously generated, and the synthetic fuel is generally not economical to produce absent the credits.

Synthetic Fuel Risks Associated With Crude Oil Prices

Recent unprecedented and unanticipated increases in the price of oil could limit the amount of Section 29 tax credits or eliminate them altogether. Section 29 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 value (the "Threshold Price"), the amount of Section 29 tax credits are reduced for that year. Also, if the Annual Average Price increases high enough (the "Phase Out Price"), the Section 29 tax credits are eliminated for that year. For 2003, the Threshold Price was $50.14 per barrel and the Phase Out Price was $62.94 per barrel. The Threshold Price and the Phase Out Price are adjusted annually for inflation. Although data for 2004 is not yet available, we do not expect the amount of our 2004 Section 29 tax credits to be adversely affected by oil prices. We cannot predict with any certainty the Annual Average Price for 2005 or beyond. Therefore, we cannot predict whether the price of oil will have a material effect on our synthetic fuel business after 2004. However, if during 2005 through 2007, oil prices remain at historically high levels or increase, our synthetic fuel business may be adversely affected for those years and, depending on the magnitude of such increases in oil prices, the adverse affect for those years could be material and could have an impact on our synthetic fuel production plans which, in turn, may have a material impact on our results of operations and financial condition.

There are risks involved with the operation of our nonregulated plants, including dependence on third parties and related counter-party risks, and a lack of operating history, all of which may make our wholesale generation and overall operations less profitable and more unstable.

At December 31, 2004, we had approximately 3,100 MW of nonregulated generation in commercial operation.

The operation of wholesale generation facilities is subject to many risks, including those listed below. During the execution of our wholesale generation strategy, these risks will intensify. These risks include:

- We may enter into or otherwise acquire long-term contracts that take effect at a future date based upon our current expectations of our future wholesale generation capacity. If our expected future capacity does not meet our expectations, we may not be able to meet our obligations under any such long-term contracts and may have to purchase power in the spot market at then prevailing prices. Accordingly, we may lose current and future customers, impair our ability to implement our wholesale strategy, and suffer reputational harm. Additionally, if we are unable to secure favorable pricing in the spot market, our results of operations may be diminished. We may also become liable under any related performance guarantees then in existence.

- Our wholesale facilities depend on third parties through power purchase agreements, fuel supply and transportation agreements, and transmission grid connection agreements. If such third parties breach their obligations to us, our revenues, financial condition, cash flow and ability to make payments of interest and principal on our outstanding debts may be impaired. Any material breach by any of these parties of their obligations under the project contracts could adversely affect our cash flows.

- We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity and natural gas that we sell to the wholesale market. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual obligations may be hindered. Although the FERC has issued regulations designed to encourage competition in wholesale market transactions for electricity, there is the potential that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electric power as we desire. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets.

- Agreements with our counter-parties frequently will include the right to terminate and/or withhold payments or performance under the contracts if specific events occur. If a project contract were to be terminated due to nonperformance by us or by the other party to the contract, our ability to enter into a substitute agreement having substantially equivalent terms and conditions is uncertain.

- Because many of our facilities are newly constructed and have no significant operating history, various unexpected events may increase our expenses or reduce our revenues. As with any new business venture of this size and nature, operation of our facility could be affected by many factors, including start-up problems, the breakdown or failure of equipment or processes, the performance of our facility below expected levels of output or efficiency, failure to operate at design specifications, labor disputes, changes in law, failure to obtain necessary permits or to meet permit conditions, government exercise of eminent domain power or similar events and catastrophic events including fires, explosions, earthquakes and droughts.

- Our facilities seek to enter into long-term power purchase agreements to sell all or a portion of their generating capacity. CCO currently owns six electricity generation facilities with approximately 3,100 MW of generation capacity, and it has contractual rights to an additional 2,500 MW of generation capacity from mixed fuel generation facilities through its agreements with 16 Georgia electric membership cooperatives (EMCs). CCO has contracts for its combined production capacity of approximately 77% for 2005, 81% for 2006 and 75% for 2007. Three above-market tolling agreements for approximately 1,200 MW of capacity expired at the end of 2004. CCO has replaced the expired agreements with the increased cooperative load in Georgia. The increased cooperative load in Georgia will significantly increase CCO's revenue and cost of sales from 2004 to 2005 with lower margins expected. Following the expiration or early termination of our power purchase agreements, or to the extent we cannot otherwise secure contracts for our current and future generation capacity, our facilities will generally become merchant facilities. Our merchant facilities may not be able to find adequate purchasers, attain favorable pricing, or otherwise compete effectively in the wholesale market. Additionally, numerous legal and regulatory limitations restrict our ability to operate a facility on a wholesale basis.

Our energy marketing and trading operations are subject to risks that may reduce our revenues and adversely impact our results of operations and financial condition, many of which are beyond our control.

Our fleet of nonregulated plants may sell energy into the spot market or other competitive power markets or on a contractual basis. We may also enter into contracts to purchase and sell electricity, natural gas and coal as part of our power marketing and energy trading operations. Our business may also include entering into long-term contracts that supply customers' full electric requirements. More recently we have moved from tolling arrangements to full requirements contracts which have lower margins. These contracts do not guarantee us any rate of return on our capital investments through mandated rates, and our revenues and results of operations from these contracts are likely to depend, in large part, upon prevailing market prices for power in our regional markets and other competitive markets. These market prices can fluctuate substantially over relatively short periods of time. Trading margins may erode as markets mature, and should volatility decline, we may have diminished opportunities for gain.

In particular, we believe that over the past few years, the Southeastern wholesale energy market has been overbuilt and accordingly believe that supply exceeds demand. Due to this overbuilding, we believe that spot prices as well as contractual pricing will provide us with a reduced rate of return on our capital investment and our revenues and results of operations from this market will be lower than originally expected unless and until demand catches up with supply.

In addition, the Enron Corporation bankruptcy and enhanced regulatory scrutiny have contributed to more rigorous credit rating review of participants in the energy marketing and trading business. Credit downgrades of certain other market participants have significantly reduced such participants' participation in the wholesale power markets. These events are causing a decrease in the number of significant participants in the wholesale power markets, which could result in a decrease in the volume and liquidity in the wholesale power markets. We are unable to predict the impact of such developments on our power marketing and trading business.

Furthermore, the FERC, which has jurisdiction over wholesale power rates, as well as ISOs that oversee some of these markets, may impose price limitations, bidding rules and other mechanisms to address some of the volatility in these markets. Fuel prices also may be volatile, and the price we can obtain for power sales may not change at the same rate as fuel costs changes. These factors could reduce our margins and therefore diminish our revenues and results of operations.

Volatility in market prices for fuel and power may result from:

- weather conditions;
- seasonality;
- power usage;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- demand for energy commodities;
- natural gas, crude oil and refined products, and coal production levels;
- natural disasters, wars, embargoes and other catastrophic events; and
- federal, state and foreign energy and environmental regulation and legislation.

We actively manage the market risk inherent in our energy marketing operations. Nonetheless, adverse changes in energy and fuel prices may result in losses in our earnings or cash flows and adversely affect our balance sheet. Our marketing and risk management procedures may not work as planned. As a result, we cannot predict with precision the impact that our marketing, trading and risk management decisions may have on our business, operating results or financial position. In addition, to the extent that we do not cover the entire exposure of our assets or our positions to market price volatility, or our hedging procedures do not work as planned, fluctuating commodity prices could cause our sales and net income to be volatile.

Our Fuels business segment is involved in natural gas drilling and production, coal terminal services, coal mining, and fuel transportation and delivery operations that are subject to risks that may reduce our revenues and adversely impact our results of operations and financial condition.

The Fuels business segment engages in businesses that have significant operational and financial risk. Operational risk includes the activities involved with natural gas drilling, coal mining, terminal and barge operations and fuel delivery. Financial risks include exposure to commodity prices, primarily fuel prices. We actively manage the operational and financial risks associated with these businesses. Nonetheless, adverse changes in fuel prices and operational issues beyond our control may result in losses in our earnings or cash flows and adversely affect our balance sheet.

PROGRESS ENERGY CAROLINAS, INC. RISK FACTORS

In this section, unless the context indicates otherwise, references to "our," "we," "us" or similar terms refer to Progress Energy Carolinas, Inc., and its consolidated subsidiaries. Investing in our securities involves risks, including the risks described below, that could affect the energy industry, as well as us and our business. Most of the business information as well as the financial and operational data contained in our risk factors are updated periodically in the reports we file with the SEC. Although we have tried to discuss key factors, please be aware that other risks may prove to be important in the future. New risks may emerge at any time and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Before purchasing our securities, you should carefully consider the following risks and the other information in this Annual Report, as well as the documents we file with the SEC from time to time. Each of the risks described below could result in a decrease in the value of our securities and your investment therein.

Risks Related to the Energy Industry

We are subject to fluid and complex government regulations that may have a negative impact on our business, financial condition and results of operations.

We are subject to comprehensive regulation by several federal, state and local regulatory agencies, which significantly influence our operating environment and may affect our ability to recover costs from utility customers. We are subject to regulatory oversight with respect to, among other things, rates and service for electric energy sold at retail, retail service territory and issuances of securities. In addition our operating utilities are subject to regulation with respect to transmission and sales of wholesale power, accounting and certain other matters. We are also required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

The 108th Congress spent much of 2004 working on a comprehensive energy bill. While that legislation passed the House, the Senate failed to pass the legislation in 2004. There will probably be an effort to resurrect the legislation in 2005. The legislation would have further clarified the Federal Energy Regulatory Commission's ("FERC") role with respect to Standard Market Design and mandatory Regional Transmission Organizations ("RTOs") and would have repealed the Public Utility Holding Company Act of 1935 ("PUHCA"). We cannot predict the outcome or impact of the proposed or any future energy bill.

FERC, the U.S. Nuclear Regulatory Commission ("NRC"), the U.S. Environmental Protection Agency ("EPA"), the North Carolina Utilities Commission ("NCUC") and the Public Service Commission of South Carolina ("SCPSC") regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. Although we are not a registered holding company under PUHCA, we are subject to many of the regulatory provisions of PUHCA.

We are unable to predict the impact on our business and operating results from future regulatory activities of these federal, state and local agencies. Changes in regulations or the imposition of additional regulations could have a negative impact on our business, financial condition and results of operations.

We are subject to numerous environmental laws and regulations that require significant capital expenditures, increase our cost of operations, and which may impact or limit our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. We cannot predict the outcome (financial or operational) of any related litigation that may arise.

In addition, we may be a responsible party for environmental clean up at sites identified by a regulatory body. We cannot predict with certainty the amount or timing of all future expenditures related to environmental matters because of the difficulty of estimating clean up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all PRPs.

Our compliance with environmental regulations requires significant capital expenditures that impact our financial condition. For example, in June 2002, legislation was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide ("NOx") and sulfur dioxide ("SO_2") from coal-fired power plants. We expect the capital costs required to meet these emission targets will total approximately $895 million by 2013. Over the next three years, we expect to incur approximately $510 million of total capital costs associated with this legislation.

Congress currently considering further legislation that would require reductions in air emissions of NOx, SO_2, carbon dioxide and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multi-pollutant approach to air pollution control could involve significant capital costs which could be material to our consolidated financial position or results of operations. However, we cannot predict the outcome, costs or impact of this matter. In December 2003, the EPA released its proposed Interstate Air Quality Rule, currently referred to as the Clean Air Interstate Rule (CAIR). The EPA's proposal requires 29 jurisdictions, including North Carolina, South Carolina, Georgia and Florida, to reduce NOx and SO_2 emissions in order to attain preset state NOx and SO_2 emissions levels. The rule is expected to become final in March 2005. While the air quality controls already installed and currently planned for installation to comply with the NC Clean Air legislation will reduce the costs required to meet the CAIR requirements for the our North Carolina units, additional compliance costs will be determined once the rule is finalized. 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 thirteen 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. The EPA has agreed to make a determination on the petition by August 1, 2005. PEC cannot predict the outcome or costs associated with the matter.

See additional discussion of these environmental matters in Note 17 to the Progress Energy Carolinas Consolidated Financial Statements.

We cannot assure you that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our results of operations.

The uncertain outcome regarding the timing, creation and structure of regional transmission organizations, or RTOs, may materially impact our results of operations, cash flows or financial condition.

Congress, FERC, and the state utility regulators have paid significant attention in recent years to transmission issues, including the possibility of regional transmission organizations. While these deliberations have not yet resulted in significant changes to our utilities' transmission operations, they cast uncertainty over those operations, which constitute a material portion of our assets.

For the last several years, the FERC has supported independent RTOs and has indicated a belief that it has the authority to order transmission-owning utilities to transfer operational control of their transmission assets to such RTOs. Many state regulators, including most regulators in the Southeast, have expressed skepticism over the potential benefits of RTOs and generally disagree with the FERC's interpretation of its authority to mandate RTOs. In July 2002, the FERC issued its Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR). The SMD NOPR could materially alter the manner in which transmission and generation services are provided and paid for, and includes structural separation of transmission from other utility functions and the FERC's assertion of jurisdiction over certain aspects of retail service. We cannot predict the outcome or timing of any final rules or the effect that they may have on the GridSouth proceedings.

At the state level, significant uncertainty exists with respect to what action, if any, the NCUC will ultimately take. The Company has $33 million invested in GridSouth related to startup costs at December 31, 2004. These amounts are included as a regulatory asset at December 31, 2004. The Company expects to recover these startup costs in conjunction with the GridSouth original structures or in conjunction with any alternate combined transmission structures that may be required. Furthermore, the SMD NOPR presents several uncertainties, including what percentage of our investments in GridSouth will be recovered, how the elimination of transmission charges, as proposed in the SMD NOPR, will impact us, and what amount of capital expenditures will be necessary to create a new wholesale market.

The actual structure of GridSouth or any alternative combined transmission structure, as well as the date it may become operational, depends upon the resolution of all regulatory approvals and technical issues. Given the regulatory uncertainty of the ultimate timing, structure and operations of GridSouth, or an alternate combined transmission structure, we cannot predict whether it will be created, or whether it will have any material adverse effect on our future consolidated results of operations, cash flows or financial condition.

Since weather conditions directly influence the demand for and cost of providing electricity, our results of operations, financial condition and cash flows can fluctuate on a seasonal or quarterly basis and can be negatively affected by changes in weather conditions and severe weather.

Our results of operations, financial condition, cash flows and ability to pay dividends on our common stock may be affected by changing weather conditions. Weather conditions in our service territories in North Carolina and South Carolina directly influence the demand for electricity affect the price of energy commodities necessary to provide electricity to our customers and energy commodities that our nonregulated businesses sell.

Electric power demand is generally a seasonal business. In many parts of the country, demand for power and market prices peak during the hot summer months. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the nature and location of facilities we acquire and the terms of power sale contracts into which we enter. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather could diminish our results of operations and harm our financial condition.

Furthermore, severe weather in these states, such as hurricanes, tornadoes, severe thunderstorms, snow and ice storms, can be destructive, causing outages, downed power lines and property damage, requiring us to incur additional and unexpected expenses and causing us to lose generating revenues.

Our ability to recover significant costs resulting from severe weather events is subject to regulatory oversight and the timing and amount of any such recovery is uncertain and may impact our financial conditions.

PEC is not required to maintain a storm damage reserve account and does not have an ongoing regulatory mechanism to recover storm costs and; therefore, hurricane restoration costs recorded in the third quarter of 2004 were charged to operations and maintenance expenses or capital expenditures based on the nature of the work performed. In connection with other storms, PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over a five-year period. PEC did not seek recovery of 2004 storm costs from the NCUC.

Our revenues, operating results and financial condition may fluctuate with the economy and its corresponding impact on our commercial and industrial customers as well as the demand and competitive state of the wholesale market.

Our business is impacted by fluctuations in the macroeconomy. For the year ended December 31, 2004, commercial and industrial customers represented approximately 25% and 19%, respectively, of our billed electric revenues. As a result, changes in the macroeconomy can have negative impacts on our revenues. As our commercial and industrial customers experience economic hardships, our revenues can be negatively impacted. In recent years, in North and South Carolina, sales to industrial customers have been affected by downturns in the textile and chemical industries.

For the year ended December 31, 2004, 16% of our billed electric revenues were from wholesale sales. Wholesale revenues fluctuate with regional demand, fuel prices, and contracted capacity. Our wholesale profitability is dependent upon our ability to renew or replace expiring wholesale contracts on favorable terms. During 2004, wholesale revenues decreased from expiring contracts being renegotiated by us at less favorable terms due to slightly depressed markets and from increased competition in the wholesale markets served by us. If this trend market environment persists, we may experience further declines in our wholesale revenues.

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. Given the difficulty PEC believes it would experience in passing one of the interim screens, on August 12, 2004, PEC notified the FERC that it would revise its Market-based Rate tariff to restrict it to sales outside our control area and file a new cost-based tariff for sales within our control area that incorporates the FERC's default cost-based rate methodologies for sales of one year or less. We anticipate making this filing the first quarter of 2005. We cannot predict what impact our requirement to implement cost-based tariffs will have on our future financial condition, results of operations or cash flows.

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect our financial condition, results of operations or cash flows.

Increased competition resulting from deregulation or restructuring efforts could have a significant adverse financial impact on us and our utility subsidiaries and consequently on our results of operations and cash flows. Increased competition could also result in increased pressure to lower costs, including the cost of electricity. Retail competition and the unbundling of regulated energy and gas service could have a significant adverse financial impact on us and our subsidiaries due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Because we have not previously operated in a competitive retail environment, we cannot predict the extent and timing of entry by additional competitors into the electric markets. Due to several factors, however, there currently is little discussion of any movement toward deregulation in North Carolina and South Carolina. We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our financial condition, results of operations or cash flows.

Increased commodity prices may adversely affect the financial condition, results of operations or cash flows of us and our utilities' businesses.

We are exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related products marketed and purchased as a result of its ownership of energy-related assets. While each state commission allows electric utilities to recover certain of these costs through various cost recovery clauses, there is the potential that these future costs could be deemed imprudent by the respective commissions. There is also a delay between the timing of when these costs are incurred by the utilities and when these costs are recovered from the ratepayers, which can adversely impact our cash flows.

Prices for SO_2 emission allowance credits under the EPA's emission trading program increased significantly during 2004. While SO_2 allowances are eligible for annual recovery in our jurisdiction in South Carolina, no such annual recovery exists in North Carolina. Future increases in the price of SO_2 allowances could have a significant adverse financial impact on us and consequently on our results of operations and cash flows.

Risks Related to Us and Our Business

The rates that we may charge retail customers for electric power are subject to the authority of state regulators. Accordingly, our profit margins could be adversely affected if we do not control operating costs.

The NCUC and the SCPSC each exercise regulatory authority for review and approval of the retail electric power rates charged within its respective state. State regulators may not allow our utility subsidiaries to increase retail rates in the manner or to the extent requested by those subsidiaries. State regulators may also seek to reduce retail rates.

Additionally, under the NC Clean Air legislation in North Carolina, passed in 2002, PEC's base retail rates were frozen for five years unless there are significant cost changes due to governmental action, significant expenditures due to force majeure or other extraordinary events beyond our control, and we have agreed not to seek a base retail electric rate increase in South Carolina through 2005. The same legislation required a significant increase in capital expenditures over the next several years for clean air improvements. The cash costs incurred by us is generally not subject to being fixed or reduced by state regulators. We will also require dedicated capital expenditures. Thus, our ability to maintain our profit margins depends upon stable demand for electricity and our efforts to manage our costs.

There are inherent potential risks in the operation of nuclear facilities, including environmental, health, regulatory, terrorism, and financial risks that could result in fines or the shutdown of our nuclear units, which may present potential exposures in excess of our insurance coverage.

We own and operate four nuclear units that represent approximately 3,448 MW, or 28%, of our generation capacity for the year ended December 31, 2004. Our nuclear facilities are subject to environmental, health and financial risks such as the ability to dispose of spent nuclear fuel, the ability to maintain adequate capital reserves for decommissioning, potential liabilities arising out of the operation of these facilities, and the costs of securing the facilities against possible terrorist attacks. We maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that damages could exceed the amount of our insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or to shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could require us to make substantial capital expenditures at our nuclear plants. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could materially and adversely affect our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

From time to time, our facilities require licenses that need to be renewed or extended in order to continue operating. We do not anticipate any problems renewing these licenses as required. However, as a result of potential terrorist threats and increased public scrutiny of utilities, the licensing process could result in increased licensing or compliance costs that are difficult or impossible to predict.

Our financial performance depends on the successful operation of our electric generating facilities and our ability to deliver electricity to our customers.

Operating electric generating facilities and delivery systems involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- fuel supply interruptions; and
- catastrophic events such as hurricanes, fires, earthquakes, explosions, floods, terrorist attacks or other similar occurrences.

A decrease or elimination of revenues generated from our subsidiaries' electric generating facilities and electricity delivery systems or an increase in the cost of operating the facilities could have an adverse effect on our business and results of operations.

Our business is dependent on our ability to successfully access capital markets. Our inability to access capital may limit our ability to execute our business plan, or pursue improvements and make acquisitions that we may otherwise rely on for future growth.

We rely on access to both short-term and long-term capital markets, and lines of credit with commercial banks as a significant source of liquidity for capital requirements not satisfied by the cash flow from our operations. If we are not able to access these sources of liquidity, our ability to implement our strategy will be adversely affected. We believe that we will maintain sufficient access to these financial markets based upon current credit ratings. However, certain market disruptions or a downgrade of our credit rating to below investment grade would increase our cost of borrowing and may adversely affect our ability to access one or more financial markets. Market disruptions create a unique uncertainty as they typically result from factors beyond are control. Such market disruptions could include:

- an economic downturn;
- the bankruptcy of an unrelated energy company;
- capital market conditions generally;
- allegations of corporate scandal at unrelated companies;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on our facilities or unrelated energy companies; or
- the overall health of the utility industry.

In addition, we believe that these market disruptions, unrelated to our business, could result in a ratings downgrade and, correspondingly, increase our cost of capital. Additional risks regarding the impact of a ratings downgrade are discussed below. Restrictions on our ability to access financial markets may affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth.

Increases in our leverage could adversely affect our competitive position, business planning and flexibility, financial condition, ability to service our debt obligations and to pay dividends on our common stock, and ability to access capital on favorable terms.

Our cash requirements arise primarily from the capital-intensive nature of our electric utilities. In addition to operating cash flows, we rely heavily on our commercial paper and long-term debt. At December 31, 2004, our commercial paper and bank borrowings and long-term debt balances were as follows (in millions):

Company	Outstanding Commercial Paper and Bank Borrowings	Total Long-Term Debt, Net
PEC	221	2,750 (a)

(a) Net of current portion, which at December 31, 2004, was $300 million.

At December 31, 2004, we had two committed credit lines that support our commercial paper programs totaling $450 million. While our financial policy precludes us from issuing commercial paper in excess of our credit lines, at December 31, 2004, we had outstanding borrowings on our credit facilities of $90 million and an outstanding commercial paper balance of $131 million, leaving an additional $229 million available for future borrowing under our credit lines.

Our credit lines impose various limitations that could impact our liquidity. Our credit facilities include a defined maximum total debt to total capital (leverage) ratio. At December 31, 2004, the maximum and actual leverage ratios, pursuant to the terms of the credit facilities, were 65% and 52.3%, respectively. Under the credit facilities, indebtedness includes certain letters of credit and guarantees which are not recorded on our Consolidated Balance Sheets.

In the event our capital structure changes such that we approach the permitted ratios, our access to capital and additional liquidity could decrease. Furthermore, our credit lines include provisions under which lenders could refuse to advance funds to each company under their respective credit lines in the event of a material adverse change in the respective company's financial condition. A limitation in our liquidity could have a material adverse impact on our business strategy and our ongoing financing needs.

Our indebtedness also includes several cross-default provisions which could significantly impact our financial condition. Our credit lines include cross-default provisions for defaults of indebtedness in excess of $10 million. Under these provisions, if the applicable borrower or certain subsidiaries fail to pay various debt obligations in excess of $10 million, the lenders could accelerate payment of any outstanding borrowings and terminate their commitments to the credit facility. Our cross-default provisions only apply to defaults of indebtedness, but not defaults by our affiliates.

Changes in economic conditions could result in higher interest rates, which would increase our interest expense on our floating rate debt and reduce funds available to us for our current plans. Additionally, an increase in our leverage could adversely affect us by:

- increasing the cost of future debt financing;
- making it more difficult for us to satisfy our existing financial obligations;
- limiting our ability to obtain additional financing, if we need it, for working capital, acquisitions, debt service requirements or other purposes;
- increasing our vulnerability to adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete;
- placing us at a competitive disadvantage compared to our competitors who have less debt; and
- causing a downgrade in our credit ratings.

Any reduction in our credit ratings which would cause us to be rated below investment grade would likely increase our borrowing costs, limit our access to additional capital and require posting of collateral, all of which could materially and adversely affect our business, results of operations and financial condition.

Our senior secured debt has been assigned a rating by Standard & Poor's Ratings Group, a division of The McGraw Hill Companies, Inc., of "BBB" (negative outlook), by Moody's Investors Service, Inc. of "A3" (stable outlook). Our senior unsecured debt rating has been assigned a rating by S&P of "BBB" (negative outlook) and by Moody's of "Baa1" (stable outlook). In addition, S&P's rating philosophy links the ratings of a utility subsidiary to the credit rating of its parent corporation. Accordingly, if S&P were to downgrade Progress Energy, Inc.'s credit ratings, our credit rating would also likely be downgraded, regardless of whether or not we had experienced any change in our business operations or financial conditions. We will seek to maintain a solid investment grade rating through prudent capital management and financing structures. We cannot, however, assure you that our current ratings will remain in effect for any given period of time or that our ratings will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade could increase our borrowing costs and adversely affect our access to capital, which could negatively impact our financial results. Further, we may be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease. In October 2004, S&P reduced our short-term debt rating to A-3 from A-2. As a result of the impact of these actions, we have borrowed on our revolving credit agreements. Due to the lower short-term debt rating issued by S&P, we may continue to borrow under our revolving credit facilities instead of issuing commercial paper due to the difference in investor demand for lower-rated commercial paper. We note that the ratings from credit agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

We use derivatives, including futures, forwards and swaps, to manage our commodity and financial market risks. In the future, we could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized.

Date: March 16, 2005

PROGRESS ENERGY, INC.
CAROLINA POWER & LIGHT COMPANY
(Registrants)

By: /s/ Robert B. McGehee
Robert B. McGehee
Chief Executive Officer
Progress Energy, Inc.

By: /s/ Fred N. Day IV
Fred N. Day IV
President and Chief Executive Officer
Carolina Power & Light Company

By: /s/ Geoffrey S. Chatas
Geoffrey S. Chatas
Executive Vice President and
Chief Financial Officer
Progress Energy, Inc.
Carolina Power & Light Company

By: /s/ Robert H. Bazemore, Jr.
Robert H. Bazemore, Jr.
Controller
(Chief Accounting Officer)
Progress Energy, Inc.
Carolina Power & Light Company

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
/s/ Robert B. McGehee (Robert B. McGehee, Chairman)	Director	March 16, 2005
/s/ Edwin B. Borden (Edwin B. Borden)	Director	March 16, 2005
/s/ James E. Bostic, Jr. (James E. Bostic, Jr.)	Director	March 16, 2005
/s/ David L. Burner (David L. Burner)	Director	March 16, 2005

/s/ Charles W. Coker (Charles W. Coker)	Director	March 16, 2005
/s/ Richard L. Daugherty (Richard L. Daugherty)	Director	March 16, 2005
/s/ W.D. Frederick, Jr. (W.D. Frederick, Jr.)	Director	March 16, 2005
/s/ William O. McCoy (William O. McCoy)	Director	March 16, 2005
/s/ E. Marie McKee (E. Marie McKee)	Director	March 16, 2005
/s/ John H. Mullin, III (John H. Mullin, III)	Director	March 16, 2005
/s/ Richard A. Nunis (Richard A. Nunis)	Director	March 16, 2005
/s/Peter S. Rummell (Peter S. Rummell)	Director	March 16, 2005
/s/ Carlos A. Saladrigas (Carlos A. Saladrigas)	Director	March 16, 2005
/s/ Jean Giles Wittner (Jean Giles Wittner)	Director	March 16, 2005

EXHIBIT INDEX

Number	Exhibit	Progress Energy, Inc.	PEC
*2(a)	Agreement and Plan of Exchange, dated as of August 22, 1999, by and among Carolina Power & Light Company, Florida Progress Corporation and CP&L Holdings, Inc. (filed as Exhibit 2.1 to Current Report on Form 8-K dated August 22, 1999, File No. 1-3382).	X	X
*2(b)	Amended and Restated Agreement and Plan of Exchange, by and among Carolina Power & Light Company, Florida Progress Corporation and CP&L Energy, Inc., dated as of August 22, 1999, amended and restated as of March 3, 2000, (filed as Annex A to Joint Preliminary Proxy Statement of Carolina Power & Light Company and Florida Progress Corporation dated March 6, 2000, File No. 1-3382).	X	X
*3a(1)	Restated Charter of Carolina Power & Light Company, as amended May 10, 1995, (filed as Exhibit No. 3(i) to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1995, File No. 1-3382).		X
*3a(2)	Restated Charter of Carolina Power & Light Company as amended on May 10, 1996, (filed as Exhibit No. 3(i) to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997, File No. 1-3382).		X
*3a(3)	Amended and Restated Articles of Incorporation of CP&L Energy, Inc., as amended and restated on June 15, 2000, (filed as Exhibit No. 3a(1) to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15929 and No. 1-3382).	X	
*3b(1)	Amended and Restated Articles of Incorporation of CP&L Energy, Inc., as amended and restated on December 4, 2000, (filed as Exhibit 3b(1) to Annual Report on Form 10-K dated March 28, 2002, File No. 1-3392 and 1-15929).	X	
*3b(2)	By-Laws of Carolina Power & Light Company, as amended on March 17, 2004, (filed as Exhibit No. 3(ii)(b) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, File No. 1-3382 and 1-15929).		X
*3b(3)	By-Laws of Carolina Power & Light Company, as amended on December 12, 2001 (filed as Exhibit 3b(2) to Annual Report on Form 10-K dated March 28, 2002, File No. 1-3382 and 1-15929).		X
*3b(4)	By-Laws of Progress Energy, Inc., as amended on March 17, 2004, (filed as Exhibit No. 3(ii)(a) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, File No. 1-3382 and 1-15929).	X	

*3b(5)	By-Laws of Progress Energy, Inc., as amended and restated December 12, 2001, (filed as Exhibit No. 3 to Current Report on Form 8-K dated January 17, 2002, File No. 1-15929).	X	
*4a(1)	Resolution of Board of Directors, dated December 8, 1954, authorizing the issuance of, and establishing the series designation, dividend rate and redemption prices for Carolina Power & Light Company's Serial Preferred Stock, $4.20 Series (filed as Exhibit 3(c), File No. 33-25560).		X
*4a(2)	Resolution of Board of Directors, dated January 17, 1967, authorizing the issuance of, and establishing the series designation, dividend rate and redemption prices for Carolina Power & Light Company's Serial Preferred Stock, $5.44 Series (filed as Exhibit 3(d), File No. 33-25560).		X
*4a(3)	Statement of Classification of Shares dated January 13, 1971, relating to the authorization of, and establishing the series designation, dividend rate and redemption prices for Carolina Power & Light Company's Serial Preferred Stock, $7.95 Series (filed as Exhibit 3(f), File No. 33-25560).		X
*4a(4)	Statement of Classification of Shares dated September 7, 1972, relating to the authorization of, and establishing the series designation, dividend rate and redemption prices for Carolina Power & Light Company's Serial Preferred Stock, $7.72 Series (filed as Exhibit 3(g), File No. 33-25560).		X
*4b(1)	Mortgage and Deed of Trust dated as of May 1, 1940, between Carolina Power & Light Company and The Bank of New York (formerly, Irving Trust Company) and Frederick G. Herbst (Douglas J. MacInnes, Successor), Trustees and the First through Fifth Supplemental Indentures thereto (Exhibit 2(b), File No. 2-64189); the Sixth through Sixty-sixth Supplemental Indentures (Exhibit 2(b)-5, File No. 2-16210; Exhibit 2(b)-6, File No. 2-16210; Exhibit 4(b)-8, File No. 2-19118; Exhibit 4(b)-2, File No. 2-22439; Exhibit 4(b)-2, File No. 2-24624; Exhibit 2(c), File No. 2-27297; Exhibit 2(c), File No. 2-30172; Exhibit 2(c), File No. 2-35694; Exhibit 2(c), File No. 2-37505; Exhibit 2(c), File No. 2-39002; Exhibit 2(c), File No. 2-41738; Exhibit 2(c), File No. 2-43439; Exhibit 2(c), File No. 2-47751; Exhibit 2(c), File No. 2-49347; Exhibit 2(c), File No. 2-53113; Exhibit 2(d), File No. 2-53113; Exhibit 2(c), File No. 2-59511; Exhibit 2(c), File No. 2-61611; Exhibit 2(d), File No. 2-64189; Exhibit 2(c), File No. 2-65514; Exhibits 2(c) and 2(d), File No. 2-66851; Exhibits 4(b)-1, 4(b)-2, and 4(b)-3, File No. 2-81299; Exhibits 4(c)-1 through 4(c)-8, File No. 2-95505; Exhibits 4(b) through 4(h), File No. 33-25560; Exhibits 4(b) and 4(c), File No. 33-33431; Exhibits 4(b) and 4(c), File No. 33-38298; Exhibits 4(h) and 4(i), File No. 33-42869; Exhibits 4(e)-(g), File No. 33-48607; Exhibits 4(e) and 4(f), File No. 33-55060; Exhibits 4(e) and 4(f), File No.		X

	33-60014; Exhibits 4(a) and 4(b) to Post-Effective Amendment No. 1, File No. 33-38349; Exhibit 4(e), File No. 33-50597; Exhibit 4(e) and 4(f), File No. 33-57835; Exhibit to Current Report on Form 8-K dated August 28, 1997, File No. 1-3382; Form of Carolina Power & Light Company First Mortgage Bond, 6.80% Series Due August 15, 2007 filed as Exhibit 4 to Form 10-Q for the period ended September 30, 1998, File No. 1-3382; Exhibit 4(b), File No. 333-69237; and Exhibit 4(c) to Current Report on Form 8-K dated March 19, 1999, File No. 1-3382.); and the Sixty-eighth Supplemental Indenture (Exhibit No. 4(b) to Current Report on Form 8-K dated April 20, 2000, File No. 1-3382; and the Sixty-ninth Supplemental Indenture (Exhibit No. 4b(2) to Annual Report on Form 10-K dated March 29, 2001, File No. 1-3382); and the Seventieth Supplemental Indenture, (Exhibit 4b(3) to Annual Report on Form 10-K dated March 29, 2001, File No. 1-3382); and the Seventy-first Supplemental Indenture (Exhibit 4b(2) to Annual Report on Form 10-K dated March 28, 2002, File No. 1-3382 and 1-15929); and the Seventy-second Supplemental Indenture (Exhibit 4 to PEC Report on Form 8-K dated September 12, 2003, File No. 1-3382).		
*4c(1)	Indenture, dated as of February 15, 2001, between Progress Energy, Inc. and Bank One Trust Company, N.A., as Trustee, with respect to Senior Notes (filed as Exhibit 4(a) to Form 8-K dated February 27, 2001, File No. 1-15929).	X	
*4c(2)	Indenture, dated as of March 1, 1995, between Carolina Power & Light Company and Bankers Trust Company, as Trustee, with respect to Unsecured Subordinated Debt Securities (filed as Exhibit No. 4(c) to Current Report on Form 8-K dated April 13, 1995, File No. 1-3382).		X
*4c(3)	Resolutions adopted by the Executive Committee of the Board of Directors at a meeting held on April 13, 1995, establishing the terms of the 8.55% Quarterly Income Capital Securities (Series A Subordinated Deferrable Interest Debentures) (filed as Exhibit 4(b) to Current Report on Form 8-K dated April 13, 1995, File No. 1-3382).		X
*4d	Indenture (for Senior Notes), dated as of March 1, 1999, between Carolina Power & Light Company and The Bank of New York, as Trustee, (filed as Exhibit No. 4(a) to Current Report on Form 8-K dated March 19, 1999, File No. 1-3382), and the First and Second Supplemental Senior Note Indentures thereto (Exhibit No. 4(b) to Current Report on Form 8-K dated March 19, 1999, File No. 1-3382); Exhibit No. 4(a) to Current Report on Form 8-K dated April 20, 2000, File No. 1-3382).		X
*4e	Indenture (For Debt Securities), dated as of October 28, 1999, between Carolina Power & Light Company and The Chase Manhattan Bank, as Trustee (filed as Exhibit 4(a) to Current Report on Form 8-K dated November 5, 1999, File No. 1-3382), and an Officer's Certificate issued pursuant thereto, dated as of October 28, 1999, authorizing the issuance and sale of Extendible Notes due October 28,		X

	2009 (Exhibit 4(b) to Current Report on Form 8-K dated November 5, 1999, File No. 1-3382).		
*4f	Contingent Value Obligation Agreement, dated as of November 30, 2000, between CP&L Energy, Inc. and The Chase Manhattan Bank, as Trustee (Exhibit 4.1 to Current Report on Form 8-K dated December 12, 2000, File No. 1-3382).	X	
*10a(1)	Purchase, Construction and Ownership Agreement dated July 30, 1981, between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981, changing name to North Carolina Eastern Municipal Power Agency, amending letter dated February 18, 1982, and amendment dated February 24, 1982, (filed as Exhibit 10(a), File No. 33-25560).		X
*10a(2)	Operating and Fuel Agreement dated July 30, 1981, between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981, changing name to North Carolina Eastern Municipal Power Agency, amending letters dated August 21, 1981 and December 15, 1981, and amendment dated February 24, 1982 (filed as Exhibit 10(b), File No. 33-25560).		X
*10a(3)	Power Coordination Agreement dated July 30, 1981, between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981, changing name to North Carolina Eastern Municipal Power Agency and amending letter dated January 29, 1982, (filed as Exhibit 10(c), File No. 33-25560).		X
*10a(4)	Amendment dated December 16, 1982 to Purchase, Construction and Ownership Agreement dated July 30, 1981, between Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency (filed as Exhibit 10(d), File No. 33-25560).		X
*10a(5)	Agreement Regarding New Resources and Interim Capacity between Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency dated October 13, 1987, (filed as Exhibit 10(e), File No. 33-25560).		X
*10a(6)	Power Coordination Agreement – 1987A between North Carolina Eastern Municipal Power Agency and Carolina Power & Light Company for Contract Power From New Resources Period 1987-1993 dated October 13, 1987, (filed as Exhibit 10(f), File No. 33-25560).		X
*10b(1)	Progress Energy, Inc. $600,000,000 364-Day Revolving Credit Agreement dated as of January 31, 2005, (filed as Exhibit 10 to Current Report on Form 8-K filed February 4, 2005, File No. 1-15929).	X	

*10b(2)	Progress Energy, Inc. $1,130,000,00 five-year Revolving Credit Agreement dated as of August 5, 2004, (filed as Exhibit 10(i) to Quarterly Report on Form 10-Q for the period ended June 30, 2004, File No. 1-3382 and 1-15929).	X	
*10b(3)	Amendment and Restatement, dated as of July 30, 2003, to the 364-Day Revolving Credit Agreement among PEC and certain lenders (filed as Exhibit 10(v) to Quarterly Report on Form 10-Q for the period ended June 30, 2003, File No. 1-03382 and 1-15929).		X
*10b(4)	Notice, dated March 25, 2003, to the Agent for the Lenders named in the PEC 364-Day Revolving Credit Agreement, dated July 31, 2002, of a commitment reduction in the amount of $120,000,000 (filed as Exhibit 10(ii) to Quarterly Report on Form 10-Q for the period ended March 31, 2003, File No. 1-03382 and 1-15929).		X
*10b(5)	Assumption Agreement from The Bank of New York dated August 5, 2002, for a total commitment of $25 million, increasing the amount of the PEC 364-Day and three-year Revolving Credit Agreements, dated as of July 31, 2002, to $285,000,000 each (filed as Exhibit 10(v) to Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2002, File No. 1-03382 and 1-15929).		X
*10b(6)	Carolina Power & Light Company $272,500,000 364-Day Revolving Credit Agreement dated as of July 31, 2002, (filed as Exhibit 10(iii) to Quarterly Report on Form 10-Q for the period ended September 30, 2002, File No. 1-3382 and 1-15929).		X
*10b(7)	Carolina Power & Light Company $272,500,000 three-year Revolving Credit Agreement dated as of July 31, 2002, (filed as Exhibit 10(iv) to Quarterly Report on Form 10-Q for the period ended September 30, 2002, File No. 1-3382 and 1-15929).		X
*10b(8)	PEF 364-Day $200,000,000 Credit Agreement dated as of April 1, 2003 (filed as Exhibit 10(ii) to Florida Power Corporation Form 10-Q for the quarter ended March 31, 2003).	X	
*10b(9)	PEF three-year $200,000,000 Credit Agreement, dated as of April 1, 2003, (filed as Exhibit 10(iii) to the Florida Power Corporation Form 10-Q for the quarter ended March 31, 2003).	X	
10b(10)	Amendment, dated as of March 11, 2005, to the $1,130,000,000 5-Year Revolving Credit Agreement among Progress Energy, Inc. and certain lenders, dated August 5, 2004.	X	
-+*10c(1)	Retirement Plan for Outside Directors (filed as Exhibit 10(i), File No. 33-25560).		X
-+*10c(2)	Resolutions of the Board of Directors dated May 8, 1991, amending the PEC Directors Deferred Compensation Plan (filed as Exhibit 10(b), File No. 33-48607).	X	X

+*10c(3)	Resolutions of Board of Directors dated July 9, 1997, amending the Deferred Compensation Plan for Key Management Employees of Carolina Power & Light Company.		X
-+*10c(4)	Carolina Power & Light Company Restricted Stock Agreement, as approved January 7, 1998, pursuant to the Company's 1997 Equity Incentive Plan (filed as Exhibit No. 10 to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 1998, File No. 1-3382.)	X	X
+*10c(5)	1997 Equity Incentive Plan, Amended and Restated as of September 26, 2001, (filed as Exhibit 4.3 to Progress Energy Form S-8 dated September 27, 2001, File No. 1-3382).	X	X
-+*10c(6)	Performance Share Sub-Plan of the 1997 Equity Incentive Plan, as amended January 1, 2001, (filed as Exhibit 10c(11) to Annual Report on Form 10-K dated March 28, 2002, File No. 1-3382 and 1-15929).	X	X
+*10c(7)	Progress Energy, Inc. Form of Stock Option Agreement (filed as Exhibit 4.4 to Form S-8 dated September 27, 2001, File No. 333-70332).	X	X
+*10c(8)	Progress Energy, Inc. Form of Stock Option Award (filed as Exhibit 4.5 to Form S-8 dated September 27, 2001, File No. 333-70332).	X	X
+*10c(9)	2002 Progress Energy, Inc. Equity Incentive Plan, amended and restated July 10, 2002, (filed as Exhibit 10(vi) to Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2002, File No. 1-3382 and 1-15929).	X	X
+*10c(10)	Amended Management Incentive Compensation Plan of Progress Energy, Inc., effective January 1, 2005, (filed as Exhibit 10(i) to current report on Form 8-K dated December 13, 2004, File Nos. 1-3382, 1-3274, 1-15929 and 1-8349).	X	X
+10c(11)	Progress Energy, Inc., Amended and Restated Management Deferred Compensation Plan, Adopted as of January 1, 2000, as Revised and Restated, effective as of January 1, 2005.	X	X
+10c(12)	Progress Energy, Inc. Amended and Restated Management Effective as of January 1, 2005.	X	X
+10c(13)	Amended Performance Share Sub-Plan of the 2002 Progress Energy, Inc. Equity Incentive Plan effective as of January 1, 2005.	X	X
+*10c(14)	Form of Deferred Compensation Plan for Directors-- Method of Payment Agreement of Progress Energy, Inc., effective as of January 1, 2005 (filed as Exhibit 10(ii) to Current Report on Form 8-K dated December 13, 2004, File Nos. 1-3382, 1-3274, 1-15929 and 1-8349).	X	X

+10c(15)	Amended and Restated Progress Energy, Inc. Restoration Retirement Plan, effective as of January 1, 2005.	X	X
+10c(16)	Amended and Restated Supplemental Senior Executive Retirement Plan of Progress Energy, Inc., amended, effective January 1, 2005.	X	X
+*10c(17)	Amended Non-Employee Director Stock Unit Plan of Progress Energy, Inc., effective January 1, 2005 (filed as Exhibit 10(iii) to Current Report on Form 8-K dated December 13, 2004, File Nos. 1-3382, 1-3274, 1-15929 and 1-8349).	X	X
+10c(18)	Form of Progress Energy, Inc. Restricted Stock Agreement pursuant to the 2002 Progress Energy Inc. Equity Incentive Plan, as amended July 2002.		
+*10c(19)	Agreement dated April 27, 1999, between Carolina Power & Light Company and Sherwood H. Smith, Jr. (filed as Exhibit 10b, File No. 1-3382).		X
+*10c(20)	Employment Agreement dated August 1, 2000, between CP&L Service Company LLC and William Cavanaugh III (filed as Exhibit 10(i) to Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	
+*10c(21)	Employment Agreement dated August 1, 2000, between CP&L Service Company LLC and Robert McGehee (filed as Exhibit 10(iv) to Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	
+*10c(22)	Employment Agreement dated August 1, 2000, between Carolina Power & Light Company and William S. "Skip" Orser (filed as Exhibit 10(ii) to Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15929 and No. 1-3382).		X
+*10c(23)	Form of Employment Agreement dated August 1, 2000, (i) between Carolina Power & Light Company and Don K. Davis; and (ii) between CP&L Service Company LLC and Peter M. Scott III (filed as Exhibit 10(v) to Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	X
+*10c(24)	Form of Employment Agreement dated August 1, 2000, between Carolina Power & Light Company and Fred Day IV, C.S. "Scotty" Hinnant and E. Michael Williams (filed as Exhibit 10(vi) to Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	X
+*10c(25)	Employment Agreement dated November 30, 2000, between Carolina Power & Light Company, Florida Power Corporation and H. William Habermeyer, Jr. (filed as Exhibit 10.(b)(32) to Florida Progress Corporation and Florida Power Corporation Annual Report on Form 10-K for the year ended December 31, 2000).	X	

+*10c(26)	Form of Employment Agreement between (i) Progress Energy Service Company and John R. McArthur, effective January 2003; (ii) Progress Energy Florida, Inc. and Jeffrey J. Lyash, dated December 15, 2003; and (iii) Progress Energy Carolinas, Inc. and Lloyd M. Yates, effective January 2005 (filed as Exhibit 10c(27) to Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-3382 and 1-5929).	X	X
+*10c(27)	Employment Agreement dated October 1, 2003, between Progress Energy Service Company LLC and Geoffrey S. Chatas (filed as Exhibit 10c(28) to the Progress Energy, Inc. Annual Report on Form 10-K for the year-ended December 31, 2003).	X	X
+10c(28)	Agreement dated March 31, 2004, between Progress Energy, Inc. and William Cavanaugh III.	X	X
+10c(29)	Employment Agreement dated January 1, 2005, between Progress Energy Carolinas, Inc. and William D. Johnson.	X	X
+*10c(30)	Employment Agreement dated August 1, 2000, between Carolina Power & Light Company and Tom Kilgore (filed as Exhibit 10(iii) to Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	X
10d(1)	Agreement dated November 18, 2004, between Winchester Production Company, Ltd., TGG Pipeline Ltd., Progress Energy, Inc. and EnCana Oil & Gas (USA), Inc.	X	
*10d(2)	Precedent and Related Agreements among Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), Southern Natural Gas Company ("SNG"), Florida Gas Transmission Company ("FGT"), and BG LNG Services, LLC ("BG"), including: a) Precedent Agreement by and between SNG and PEF, dated December 2, 2004; b) Gas Sale and Purchase Contract between BG and PEF, dated December 1, 2004; c) Interim Firm Transportation Service Agreement by and between FGT and PEF, dated December 2, 2004; d) Letter Agreement between FGT and PEF, dated December 2, 2004, and Firm Transportation Service Agreement by and between FGT and PEF to be entered into upon satisfaction of certain conditions precedent; e) Discount Agreement between FGT and PEF, dated December 2, 2004; f) Amendment to Gas Sale and Purchase Contract between BG and PEF, dated January 28, 2005; and g) Letter Agreement between FGT and PEF, dated January 31, 2005,	X	

	(filed as Exhibit 10.1 to Current Report on Form 8-K/A filed March 15, 2005). (Confidential treatment has been requested for portions of this exhibit. These portions have been omitted from the above-referenced Current Report and submitted separately to the SEC.)		
12	Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges Preferred Dividends Combined.	X	X
21	Subsidiaries of Progress Energy, Inc.	X	
23(a)	Consent of Deloitte & Touche LLP.	X	X
31(a)	302 Certification of Chief Executive Officer	X	X
31(b)	302 Certification of Chief Financial Officer	X	X
32(a)	906 Certification of Chief Executive Officer	X	X
32(b)	906 Certification of Chief Financial Officer	X	X

*Incorporated herein by reference as indicated.
+Management contract or compensation plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14 (c) of Form 10-K.
-Sponsorship of this management contract or compensation plan or arrangement was transferred from Carolina Power & Light Company to Progress Energy, Inc., effective August 1, 2000.

PROGRESS ENERGY, INC.
EXHIBIT NO. 12
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(millions of dollars) Years Ended December 31	2004	2003	2002	2001	2000
Earnings, as defined:					
Income from continuing operations before cumulative effect of changes in accounting principles	$ 753	$ 811	$ 552	$ 541	$ 478
Fixed charges, as below	689	682	711	719	275
Amortization of capitalized interest	1	1	–	–	–
Preferred dividend requirements	(7)	(7)	(7)	(8)	(8)
Minority interest	17	(3)	–	–	–
Capitalized interest	(7)	(20)	(38)	–	–
Income taxes, as below	110	(119)	(166)	(162)	188
Total earnings, as defined	$ 1,556	$ 1,345	$ 1,052	$ 1,090	$ 933
Fixed Charges, as defined:					
Interest on long-term debt	$ 598	$ 613	$ 600	$ 578	$ 224
Other interest	62	42	79	112	37
Imputed interest factor in rentals – charged principally to operating expenses	22	20	25	21	9
Preferred dividend requirements of subsidiaries	7	7	7	8	8
Total fixed charges, as defined	$ 689	$ 682	$ 711	$ 719	$ 278
Income Taxes:					
Income tax expense (benefit)	$ 115	$ (111)	$ (158)	$ (154)	196
Included in AFUDC – deferred taxes in book depreciation	(5)	(8)	(8)	(8)	(8)
Total income taxes	$ 110	$ (119)	$ (166)	$ (162)	$ 188
Ratio of Earnings to Fixed Charges	2.26	1.97	1.48	1.52	3.36

PROGRESS ENERGY CAROLINAS, INC.
EXHIBIT NO. 12
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES AND
PREFERRED DIVIDENDS COMBINED AND RATIO OF EARNINGS TO FIXED CHARGES

(million of dollars) Years Ended December 31	2004	2003	2002	2001	2000
Earnings, as defined:					
Income before cumulative effect of change in accounting principles	$ 461	$ 505	$ 431	$ 364	$ 461
Fixed charges, as below	202	205	224	264	246
Income taxes, as below	234	233	199	215	282
Total earnings, as defined	$ 897	$ 943	$ 854	$ 843	$ 989
Fixed Charges, as defined:					
Interest on long-term debt	$ 183	$ 187	$ 205	$ 246	$ 224
Other interest	12	11	12	11	17
Imputed interest factor in rentals – charged principally to operating expenses	7	7	7	7	5
Total fixed charges, as defined	$ 202	$ 205	$ 224	$ 264	$ 246
Preferred dividends, as defined	$ 5	$ 4	$ 4	$ 5	$ 5
Total fixed charges and preferred dividends combined	$ 207	$ 209	$ 228	$ 269	$ 251
Income Taxes:					
Income tax expense	$ 239	$ 241	$ 207	$ 223	$ 290
Included in AFUDC – deferred taxes in book depreciation	(5)	(8)	(8)	(8)	(8)
Total income taxes	$ 234	$ 233	$ 199	$ 215	$ 282
Ratio of Earnings to Fixed Charges	4.44	4.60	3.81	3.19	4.02
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	4.33	4.51	3.75	3.13	3.94

SUBSIDIARIES OF PROGRESS ENERGY, INC.
AT DECEMBER 31, 2004

The following is a list of certain direct and indirect subsidiaries of Progress Energy, Inc., and their respective states of incorporation:

Carolina Power & Light Company d/b/a PEC	North Carolina
Florida Progress Corporation	Florida
Florida Power Corporation d/b/a/ PEF	Florida
Progress Telecommunications Corporation	Florida
Progress Telecom, LLC	Delaware
Progress Capital Holdings, Inc.	Florida
Progress Fuels Corporation	Florida
Progress Rail Services Corporation	Alabama
Progress Ventures, Inc.	North Carolina
Strategic Resource Solutions Corp.	North Carolina
Progress Energy Service Company, LLC	North Carolina

Exhibit 23.(a)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-114237 on Form S-3, Registration Statement No. 10492 on Form S-8, Registration Statement No. 33–33520 on Form S–8, Registration Statement No. 333–81278 on Form S–3, Registration Statement No. 333–81278–01 on Form S–3, Registration Statement No. 333–81278–02 on Form S–3, Registration Statement No. 333–81278–03 on Form S–3, Post–Effective Amendment 1 to Registration Statement No. 333–69738 on Form S–3, Registration Statement No. 333–70332 on Form S–8, Registration Statement No. 333–87274 on Form S–3, Post–Effective Amendment 1 to Registration Statement No. 333–47910 on Form S–3, Registration Statement No. 333–52328 on Form S–8, Post–Effective Amendment 1 to Registration Statement No. 333–89685 on Form S–8, and Registration Statement No. 333–48164 on Form S–8 of our reports dated March 7, 2005, relating to the financial statements and financial statement schedule of Progress Energy, Inc. (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2003) and management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10–K of Progress Energy, Inc. for the year ended December 31, 2004.

We also consent to the incorporation by reference in Post-Effective Amendment No. 1 to Registration Statement No. 333–58800 on Form S–3 and Registration Statement No. 333-103973 on Form S-3 of our reports dated March 7, 2005, relating to the financial statements and financial statement schedule of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC) (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2003), appearing in this Annual Report on Form 10–K of PEC for the year ended December 31, 2004.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 15, 2005

Progress Energy

March 24, 2005

U. S. Nuclear Regulatory Commission
ATTENTION: Document Control Desk
Washington, DC 20555

Dear Sir/Madam:

I am the Executive Vice President and Chief Financial Officer of Progress Energy, Inc. This letter is in support of this company's use of the financial test to demonstrate financial assurance, as specified in 10 CFR Part 50.

This company guarantees, through the parent company guarantee submitted to demonstrate compliance under 10 CFR Part 50, the decommissioning of the following facilities owned or operated by our subsidiary, Progress Energy Carolinas, Inc. The current cost estimates or certified amounts for decommissioning, and the amounts being guaranteed, are shown for each facility:

Name of Facility	Location of Facility	Current Cost Estimates	Amount Being Guaranteed
Brunswick Steam Electric Plant, Unit No. 1 (Docket No. 50-325/License No. DPR-71)	Southport, NC	$361 million	$73 million
Brunswick Steam Electric Plant, Unit No. 2 (Docket No. 50-324/License No. DPR-62)	Southport, NC	$361 million	$96 million

This company is required to file a Form 10K with the U. S. Securities and Exchange Commission for the latest fiscal year 2004.

This fiscal year of this company ends on December 31. The figures for the following items marked with an asterisk are derived from this company's independently audited, year-end financial statements and footnotes for the latest completed fiscal year ended December 31, 2004.

Progress Energy Service Company, LLC
P.O. Box 1551
Raleigh, NC 27602

FINANCIAL TEST: ALTERNATIVE II

1.	Decommissioning cost estimates or guaranteed amount for facilities Docket No. 50-325/License No. DPR-71 & Docket No. 50-324/License No. DPR-62	$169,106,924
2.	Current bond rating of most recent unsecured issuance of this firm	
	Rating:	Baa2/BBB-
	Name of rating service:	Moody's/Standard & Poor's
3.	Date of issuance of bond:	April 17, 2002
4.	Date of maturity of bond:	April 15, 2007 & April 15, 2012
*5.	Tangible net worth** (if any portion of estimates for decommissioning is included in total liabilities on your firm's financial statements, you may add the amount of that portion to this line)	$3,898,000,000
*6.	Total assets in United States (required only if less than 90 percent of firm's assets are located in the United States)	N/A

		Yes	No
7.	Is line 5 at least $10 million?	X	
8.	Is line 5 at least 6 times line 1?	X	
9.	Are at least 90 percent of firm's assets located in the United States? If not, complete line 10.	X	
10.	Is line 6 at least 6 times line 1?	N/A	
11.	Is the rating specified on line 2 "BBB" or better (if issued by Standard & Poor's) or "Baa" or better (if issued by Moody's)?	X	

* Denotes figures derived from financial statements.
** Tangible net worth is defined as net worth minus goodwill, patents, trademarks, copyrights, intangible assets, and the net book value of the nuclear units covered under the guarantee.

I hereby certify that the content of this letter is true and correct to the best of my knowledge.

Sincerely,

Geoffrey S. Chatas

Geoffrey S. Chatas
Executive Vice President and Chief Financial Officer

GSC:btm

Deloitte.

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

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

INDEPENDENT ACCOUNTANTS' REPORT ON APPLYING AGREED-UPON PROCEDURES

To the Board of Directors of Progress Energy, Inc.:

We have performed the procedures enumerated below, which were agreed to by Progress Energy, Inc. (the Company), solely to assist the Company in evaluating the *Schedule Reconciling Amounts Contained in Financial Test with Amounts in Financial Statements* of Progress Energy, Inc. as of December 31, 2004 (the Schedule) and the *Financial Test: Alternative II* (the Financial Test); prepared to support the requirements specified in Appendix A to Part 30 of 10CFR (the Requirements). The Company's management is responsible for compliance with those requirements and the preparation of the Schedule. This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. The sufficiency of these procedures is solely the responsibility of the Company. Consequently, we make no representation regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

It should be understood that (1) we make no representations regarding the Company's determination and presentation of non-GAAP measures (such as tangible net worth), and (2) the non-GAAP measure presented may not be comparable to similarly titled measures reported by other companies. However the following procedures were applied to the Schedule attached hereto as Appendix A as indicated with respect to the symbols explained below.

A. We compared these amounts to the Company's audited financial statement for the year ended December 31, 2004 and found such amounts to be in agreement.

B. We compared this amount to the Tangible Net Worth amount on the Schedule, included in the Appendix A, and found such amounts to be in agreement.

C. We compared this amount to the total net book value of the Brunswick units on a schedule prepared by Company personnel from the accounting records of the Company and found them to be in agreement. Amounts appearing in such schedule were compared with accounting records of the Company and found to be in agreement.

At your request, we proved the arithmetic accuracy of the Schedule in Appendix A.

We were not engaged to, and did not, conduct an examination, the objective of which would be the expression of an opinion on the Schedule nor Financial Test nor compliance with the requirements. Accordingly, we do not express such an opinion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

This report is intended solely for the information and use of the Board of Directors and management of Progress Energy, Inc. and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

March 25, 2005

Appendix A

SCHEDULE RECONCILING AMOUNTS CONTAINED IN FINANCIAL TEST WITH AMOUNTS IN FINANCIAL STATEMENTS

PROGRESS ENERGY, INC.
YEAR ENDED DECEMBER 31, 2004
(in millions)

Amounts Used in Calculations of Financial Test	Per Financial Statements	Reconciling Items	Per Financial Test
Total assets	$25,993	$0	$25,993
Total current liabilities	$3,061	$0	$3,061
Long-term debt, preferred stock of subs & minority interest	$9,650	$0	$9,650
Deferred credits & other liabilities	$5,649	$0	$5,649
	$18,360	$0	$18,360
Accrued decommissioning costs included in liabilities (See Note 1)	$1,261	$(229)	$1,032
Total liabilities & preferred stock of subs. (less accrued decommissioning costs)	$17,099	$229	$17,328
Net worth	$8,894	$(229)	$8,665
Less: Cost in excess of value of tangible assets acquired	$4,056	$0	$4,056
Less: Net book value of nuclear units (See Note 2)	$764	$(53)	$711
	$4,074	$(176)	$3,898
Accrued decommissioning costs included in liabilities (See Note 3)	$1,261	$(1,261)	$0
Tangible net worth (plus decommissioning costs)	$5,335	$(1,437)	$3,898

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Note 1: Reconciling item removes accrued decommissioning costs to the extent these costs have not affected net worth and includes accruals for decommissioning the non-irradiated areas at nuclear facilities included in regulatory liabilities in the financial statements.

Note 2: Reconciling item removes net asset retirement costs for Brunswick Units No. 1 & 2.

Note 3: Per Note 1 above, accrued decommissioning costs have already been added back to net worth, therefore, these costs were not added back at this point in the calculation since doing so would have taken these costs into consideration twice.

FINANCIAL TEST: ALTERNATIVE II

1.	Decommissioning cost estimates or guaranteed amount for facilities Docket No. 50-325/License No. DPR-71 & Docket No. 50-324/License No. DPR-62	$ 169,106,924		
2.	Current bond rating of most recent unsecured issuance of this firm Rating: Baa2/BBB- Name of rating service: Moody's/Standard & Poor's			
3.	Date of issuance of bond: April 17, 2002			
4.	Date of maturity of bond: April 15, 2007 & April 15, 2012			
*5.	Tangible net worth** (if any portion of estimates for decommissioning is included in total liabilities on your firm's financial statements, you may add the amount of that portion to this line)	$\boxed{\$3{,}898{,}000{,}000}$ B		
*6.	Total assets in United States (required only if less than 90 percent of firm's assets are located in the United States)	N/A		
			Yes	No
7.	Is line 5 at least $10 million?		X	
8.	Is line 5 at least 6 times line 1?		X	
9.	Are at least 90 percent of firm's assets located in the United States? If not, complete line 10.		X	
10.	Is line 6 at least 6 times line 1?		N/A	
11.	Is the rating specified on line 2 "BBB" or better (if issued by Standard & Poor's) or "Baa" or better (if issued by Moody's)?		X	

* Denotes figures derived from financial statements.
** Tangible net worth is defined as net worth minus goodwill, patents, trademarks, copyrights, intangible assets, and the net book value of the nuclear units covered under the guarantee.

ELECTRICITIES

Serving Public Power Communities Since 1965

File-4275.2
March 28, 2005

United States Nuclear Regulatory Commission
ATTENTION: Document Control Desk
Washington, DC 20555

BRUNSWICK STEAM ELECTRIC PLANT, UNITS NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT NO. 1
DOCKET NO. 50-400/LICENSE NO. DPR-63

SUBJECT: STATUS REPORT FOR DECOMMISSIONING FINANCIAL ASSURANCE

Dear Sirs/Madam:

North Carolina Eastern Municipal Power Agency (NCEMPA) submits the attached report concerning the status of its financial assurance mechanisms for decommissioning in accordance with 10CFR50.75(c) for its ownership portion of the above referenced nuclear plants which it jointly owns with Progress Energy Carolinas, Inc. (PEC). NCEMPA utilizes exclusively the external sinking fund method to provide financial assurance in accordance with 10CFR50.75(e)(l)(ii). These payments are recovered through rates established by the Board of Directors and Board of Commissioners of NCEMPA in accordance with 10CFR50.75(e)(l)(ii)(A).

This transmittal has been included along with that of PEC as a convenience to the U. S. Nuclear Regulatory Commission, however, NCEMPA is not responsible for any information contained in PEC's submittal of their status report. The attachments for NCEMPA are numbered 2 through 4 so as to correspond to those of PEC for the units jointly owned.

No new commitments are being made in this submittal.

Should you have any questions regarding this matter, please contact Al M. Conyers at (919) 760-6319.

Sincerely,

Al M. Conyers

Al M. Conyers
Chief Financial Officer
Assistant Secretary and Assistant Secretary-Treasurer

Attachments

NORTH CAROLINA EASTERN MUNICIPAL POWER AGENCY SUBMITTAL

Attachment 2
Status of Financial Assurance Mechanism

Brunswick Steam Electric Plant, Unit No. 1 (BNP) **Docket No. 50-325 / License No. DPR-71**

The following information is submitted in accordance with 10 CFR 50.75(c):

- Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b), (c) and NUREG-1307, Rev. 10:
  \$442.4 million; NCEMPA Share (18.33%) = \$81.1 million

- The fund balance for the amount accumulated as of December 31, 2004:
  \$48,243,453

- Sum of the annual amounts remaining to be collected:
  \$25,574,202 (through September 8, 2016)

- Assumptions:
  Escalation rate in decommissioning costs = 4.0%
  Earnings rate on decommissioning funds = 6.0%

- Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v).
  None

- Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report.
  None

- Material changes to trust agreements.
  None

NORTH CAROLINA EASTERN MUNICIPAL POWER AGENCY SUBMITTAL

Attachment 3
Status of Financial Assurance Mechanism

Brunswick Steam Electric Plant, Unit No. 2 (BNP) **Docket No. 50-324 / License No. DPR-62**

The following information is submitted in accordance with 10 CFR 50.75(c):

- Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b), (c) and NUREG-1307, Rev. 10:
  $442.4 million; NCEMPA Share (18.33%) = $81.1 million

- The fund balance for the amount accumulated as of December 31, 2004:
  $53,053,567

- Sum of the annual amounts remaining to be collected:
  $22,336,518 (through December 27, 2014)

- Assumptions:
  Escalation rate in decommissioning costs = 4.0%
  Earnings rate on decommissioning funds = 6.0%

- Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v).
  None

- Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report.
  None

- Material changes to trust agreements.
  None

NORTH CAROLINA EASTERN MUNICIPAL POWER AGENCY SUBMITTAL

Attachment 4
Status of Financial Assurance Mechanism

Shearon Harris Nuclear Power Plant, Unit No. 1 (HNP) **Docket No. 50-400 / License No. DPR-63**

The following information is submitted in accordance with 10 CFR 50.75(c):

- Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b), (c) and NUREG-1307, Rev. 10:
  $354.5 million; NCEMPA Share (16.17%) = $57.3 million

- The fund balance for the amount accumulated as of December 31, 2004:
  $23,097,729

- Sum of the annual amounts remaining to be collected:
  $31,290,600 (through October 24, 2026)

- Assumptions:
  Escalation rate in decommissioning costs = 4.0%
  Earnings rate on decommissioning funds = 6.0%

- Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v).
  None

- Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report.
  None

- Material changes to trust agreements.
  None

CITY OF ALACHUA
Status of Financial Assurance Mechanism
Crystal River Plant – Docket No. 50-302 / License No. DPR-72

1) Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c) and NUREG-1307, Rev. 10.

   $343,597,776 at expiration of current license on December 3, 2016.

   City of Alachua share (0.0779%) = $267,663.

2) Fund Balance for the amount of funds accumulated in the decommissioning trust fund at the end of December 31, 2004:

   $267,663 (This amount does not include additional funds collected for non-decommissioning activities, such as site restoration)

3) Annual amounts remaining to be collected:

   None

4) Assumptions:

   The assumed Cost Escalation Rate is 5.3%.

   The assumed earnings rate is 7.422% for the portion invested at a guaranteed fixed rate through 2016 (guaranteed by a forward delivery agreement) and 5.00% for the rest.

5) Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):

   None

6) Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report:

   None

7) Material changes to trust agreements:

   None

CITY OF BUSHNELL
Status of Financial Assurance Mechanism
Crystal River Plant – Docket No. 50-302 / License No. DPR-72

1) Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c) and NUREG-1307, Rev. 10.

$343,597,776 at expiration of current license on December 3, 2016.

City of Bushnell share (0.0388%) = $133,316.

2) Fund Balance for the amount of funds accumulated in the decommissioning trust fund at the end of December 31, 2004:

$133,316 (This amount does not include additional funds collected for non-decommissioning activities, such as site restoration)

3) Annual amounts remaining to be collected:

None

4) Assumptions:

The assumed Cost Escalation Rate is 5.3%.

The assumed earnings rate is 7.422% for the portion invested at a guaranteed fixed rate through 2016 (guaranteed by a forward delivery agreement) and 5.00% for the rest.

5) Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):

None

6) Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report:

None

7) Material changes to trust agreements:

None

CITY OF GAINESVILLE
Status of Financial Assurance Mechanism
Crystal River Plant -- Docket No. 50-302 / License No. DPR-72

1) Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c) and NUREG-1307, Rev. 10.

   $343,597,776 at expiration of current license on December 3, 2016.

   City of Gainesville share (1.4079%) = $4,837,513.

2) Fund Balance for the amount of funds accumulated in the decommissioning trust fund at the end of December 31, 2004:

   $4,837,513 (This amount does not include additional funds collected for non-decommissioning activities, such as site restoration)

3) Annual amounts remaining to be collected:

   None

4) Assumptions:

   The assumed Cost Escalation Rate is 5.3%.

   The assumed earnings rate is 7.422% for the portion invested at a guaranteed fixed rate through 2016 (guaranteed by a forward delivery agreement) and 5.00% for the rest.

5) Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):

   None

6) Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report:

   None

7) Material changes to trust agreements:

   None

CITY OF KISSIMMEE
Status of Financial Assurance Mechanism
Crystal River Plant -- Docket No. 50-302 / License No. DPR-72

1) Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c) and NUREG-1307, Rev. 10.

$343,597,776 at expiration of current license on December 3, 2016.

City of Kissimmee share (0.6754%) = $2,320,659.

2) Fund Balance for the amount of funds accumulated in the decommissioning trust fund at the end of December 31, 2004:

$2,320,659. (This amount does not include additional funds collected for non-decommissioning activities, such as site restoration)

3) Annual amounts remaining to be collected:

None

4) Assumptions:

The assumed Cost Escalation Rate is 5.3%.

The assumed earnings rate is 7.422% for the portion invested at a guaranteed fixed rate through 2016 (guaranteed by a forward delivery agreement) and 5.00% for the rest.

5) Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):

None

6) Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report:

None

7) Material changes to trust agreements:

None

CITY OF LEESBURG
Status of Financial Assurance Mechanism
Crystal River Plant -- Docket No. 50-302 / License No. DPR-72

1) Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c) and NUREG-1307, Rev. 10.

   $343,597,776 at expiration of current license on December 3, 2016.

   City of Leesburg share (0.8244%) = $2,832,620.

2) Fund Balance for the amount of funds accumulated in the decommissioning trust fund at the end of December 31, 2004:

   $2,832,620 (This amount does not include additional funds collected for non-decommissioning activities, such as site restoration)

3) Annual amounts remaining to be collected:

   None

4) Assumptions:

   The assumed Cost Escalation Rate is 5.3%.

   The assumed earnings rate is 7.422% for the portion invested at a guaranteed fixed rate through 2016 (guaranteed by a forward delivery agreement) and 5.00% for the rest.

5) Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):

   None

6) Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report:

   None

7) Material changes to trust agreements:

   None

CITY OF NEW SMYRNA BEACH
Status of Financial Assurance Mechanism
Crystal River Plant -- Docket No. 50-302 / License No. DPR-72

1) Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c) and NUREG-1307, Rev. 10.

$343,597,776 at expiration of current license on December 3, 2016.

City of New Smyrna Beach share (0.5608 %) = $1,926,896.

2) Fund Balance for the amount of funds accumulated in the decommissioning trust fund at the end of December 31, 2004:

$1,926,896 **(This amount does not include additional funds collected for non-decommissioning activities, such as site restoration)**

3) Annual amounts remaining to be collected:

None

4) Assumptions:

The assumed cost escalation rate is 4.00%.

The assumed earnings rate is 3.75%.

5) Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):

None

6) Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report:

None

7) Material changes to trust agreements:

None

CITY OF OCALA
Status of Financial Assurance Mechanism
Crystal River Plant – Docket No. 50-302 / License No. DPR-72

1) Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c) and NUREG-1307, Rev. 10.

   $343,597,776 at expiration of current license on December 3, 2016.

   City of Ocala share (1.3333%) = $4,581,189.

2) Fund Balance for the amount of funds accumulated in the decommissioning trust fund at the end of December 31, 2004:

   $4,581,189 (This amount does not include additional funds collected for non-decommissioning activities, such as site restoration)

3) Annual amounts remaining to be collected:

   None

4) Assumptions:

   The assumed Cost Escalation Rate is 5.3%.

   The assumed earnings rate is 7.422% for the portion invested at a guaranteed fixed rate through 2016 (guaranteed by a forward delivery agreement) and 5.00% for the rest.

5) Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):

   None

6) Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report:

   None

7) Material changes to trust agreements:

   None

ORLANDO UTILITIES COMMISSION
Status of Financial Assurance Mechanism
Crystal River Plant -- Docket No. 50-302 / License No. DPR-72

1) Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c) and NUREG-1307, Rev. 10.

   $343,597,776 at expiration of current license on December 3, 2016.

   Orlando Utilities Commission share (1.6015%) = $5,502,718.

2) Fund Balance for the amount of funds accumulated in the decommissioning trust fund at the end of December 31, 2004:

   $5,502,718. (This amount does not include additional funds collected for non-decommissioning activities, such as site restoration)

3) Annual amounts remaining to be collected:

   None

4) Assumptions:

   The assumed cost escalation rate is 5.0%.

   The assumed earnings rate is 4.25%.

5) Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):

   None

6) Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report:

   None

7) Material changes to trust agreements:

   None

SEMINOLE ELECTRIC COOPERATIVE, INC.
Status of Financial Assurance Mechanism
Crystal River Plant -- Docket No. 50-302 / License No. DPR-72

1) Amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c) and NUREG-1307, Rev. 10.

$343,597,776 at expiration of current license on December 3, 2016.

Seminole Electric Cooperative, Inc. share (1.6994%) = $5,839,101.

2) Fund Balance for the amount of funds accumulated in the decommissioning trust fund at the end of December 31, 2004:

$5,839,101 (This amount does not include additional funds collected for non-decommissioning activities, such as site restoration)

3) Annual amounts remaining to be collected (in 2000 $):

None

4) Assumptions:

The assumed cost escalation rate is 5.27%.

The assumed earnings rate is 8.00%.

5) Contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):

None

6) Modifications occurring to a licensee's current method of providing financial assurance since the last submitted report:

None

7) Material changes to trust agreements:

None