CAROLINA POWER & LIGHT COMPANY

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS

PROXY STATEMENT AND

2011 ANNUAL REPORT

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, 2011

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
	Progress Energy	
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
1-3274	**Florida Power Corporation** **d/b/a Progress Energy Florida, Inc.** 299 First Avenue North St. Petersburg, Florida 33701 Telephone: (727) 820-5151 State of Incorporation: Florida	59-0247770

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
Carolina Power & Light Company:	None
Florida Power Corporation:	None

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

Progress Energy, Inc.:	None
Carolina Power & Light Company:	$5 Preferred Stock, No Par Value
	Serial Preferred Stock, No Par Value
Florida Power Corporation:	None

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Act.

Progress Energy, Inc. (Progress Energy)	Yes	(X)	No	( )
Carolina Power & Light Company (PEC)	Yes	( )	No	(X)
Florida Power Corporation (PEF)	Yes	( )	No	(X)

Indicate by check mark whether each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Progress Energy	Yes	( )	No	(X)
PEC	Yes	( )	No	(X)
PEF	Yes	(X)	No	( )

Indicate by check mark whether each registrant (1) has 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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Progress Energy	Yes	(X)	No	( )
PEC	Yes	(X)	No	( )
PEF	Yes	( )	No	(X)

Indicate by check mark whether each registrant has submitted electronically and posted to its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

Progress Energy	Yes	(X)	No	( )
PEC	Yes	(X)	No	( )
PEF	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.

Progress Energy	( )
PEC	( )
PEF	(X)

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act:

Progress Energy	Large accelerated filer	(X)	Accelerated filer	( )
	Non-accelerated filer	( )	Smaller reporting company	( )
PEC	Large accelerated filer	( )	Accelerated filer	( )
	Non-accelerated filer	(X)	Smaller reporting company	( )
PEF	Large accelerated filer	( )	Accelerated filer	( )
	Non-accelerated filer	(X)	Smaller reporting company	( )

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Act).

Progress Energy	Yes	( )	No	(X)
PEC	Yes	( )	No	(X)
PEF	Yes	( )	No	(X)

As of June 30, 2011, the aggregate market value of the voting and nonvoting common equity of Progress Energy held by nonaffiliates was $14,107,388,747. As of June 30, 2011, the aggregate market value of the common equity of PEC held by nonaffiliates was $0. All of the common stock of PEC is owned by Progress Energy. As of June 30, 2011, the aggregate market value of the common equity of PEF held by nonaffiliates was $0. All of the common stock of PEF is indirectly owned by Progress Energy.

As of February 23, 2012, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy	Common Stock (Without Par Value)	295,219,128
PEC	Common Stock (Without Par Value)	159,608,055
PEF	Common Stock (Without Par Value)	100

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Progress Energy and PEC definitive proxy statements for the 2012 Annual Meeting of Shareholders are incorporated by reference into PART III, Items 10, 11, 12, 13 and 14 hereof. If such proxy statements are not filed with the SEC within 120 days after the end of our fiscal year, such information will be filed as part of an amendment to the Annual Report on Form 10-K/A.

This combined Form 10-K is filed separately by three registrants: Progress Energy, PEC and PEF (collectively, the Progress Registrants). Information contained herein relating to any individual registrant is filed by such registrant solely on its own behalf. Neither of PEC nor PEF make any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself.

PEF meets the conditions set forth in General Instruction I (1) (a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format permitted by General Instruction I (2) to such Form 10-K.

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GLOSSARY OF TERMS

We use the words "Progress Energy," "we," "us" or "our" to indicate that certain information relates to Progress Energy, Inc. and its subsidiaries on a consolidated basis. When appropriate, the parent holding company or the subsidiaries of Progress Energy are specifically identified on an unconsolidated basis as we discuss their various business activities.

The following abbreviations, acronyms or initialisms are used by the Progress Registrants:

TERM	DEFINITION
401(k)	Progress Energy 401(k) Savings & Stock Ownership Plan
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASLB	Atomic Safety and Licensing Board
the Asset Purchase Agreement	Agreement by and among Global, Earthco and certain affiliates, and the Progress Affiliates as amended on August 23, 2000
ASU	Accounting Standards Update
Audit Committee	Audit and Corporate Performance Committee of Progress Energy's board of directors
BART	Best Available Retrofit Technology
Base Revenues	Non-GAAP measure defined as operating revenues excluding clause recoverable regulatory returns, miscellaneous revenues, fuel and other pass-through revenues and refunds, if any
Brunswick	PEC's Brunswick Nuclear Plant
Btu	British thermal unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCRC	Capacity Cost-Recovery Clause
CERCLA or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Clean Smokestacks Act	North Carolina Clean Smokestacks Act
CO_2	Carbon dioxide
COL	Combined license
Corporate and Other	Corporate and Other segment primarily includes the Parent, Progress Energy Service Company and miscellaneous other nonregulated businesses
CR1 and CR2	PEF's Crystal River Units No. 1 and No. 2 coal-fired steam turbines
CR3	PEF's Crystal River Unit No. 3 Nuclear Plant
CR4 and CR5	PEF's Crystal River Units No. 4 and No. 5 coal-fired steam turbines
CSAPR	Cross-State Air Pollution Rule
CVO	Contingent value obligation
D.C. Court of Appeals	U.S. Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSM	Demand-side management
Duke Energy	Duke Energy Corporation
Earthco	Four coal-based solid synthetic fuels limited liability companies of which three were wholly owned

ECCR	Energy Conservation Cost Recovery Clause
ECRC	Environmental Cost Recovery Clause
EE	Energy efficiency
EGU MACT	MACT standards for coal-fired and oil-fired electric steam generating units
EIP	Equity Incentive Plan
EPA	United States Environmental Protection Agency
EPC	Engineering, procurement and construction
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
Fitch	Fitch Ratings
the Florida Global Case	*U.S. Global, LLC v. Progress Energy, Inc. et al.*
Florida Progress	Florida Progress Corporation
FPSC	Florida Public Service Commission
Funding Corp.	Florida Progress Funding Corporation, a wholly owned subsidiary of Florida Progress
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Global	U.S. Global, LLC
GWh	Gigawatt-hours
Harris	PEC's Shearon Harris Nuclear Plant
IPP	Progress Energy Investor Plus Plan
kV	Kilovolt
kVA	Kilovolt-ampere
kWh	Kilowatt-hours
Levy	PEF's proposed nuclear plant in Levy County, Fla.
LIBOR	London Inter Bank Offered Rate
MACT	Maximum achievable control technology
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations contained in PART II, Item 7 of this Form 10-K
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
the Merger	Proposed merger between Progress Energy and Duke Energy
the Merger Agreement	Agreement and Plan of Merger, dated as of January 8, 2011, by and among Progress Energy and Duke Energy
MGP	Manufactured gas plant
MW	Megawatts
MWh	Megawatt-hours
Moody's	Moody's Investors Service, Inc.
NAAQS	National Ambient Air Quality Standards
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCUC	North Carolina Utilities Commission
NDT	Nuclear decommissioning trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NO_2	Nitrogen dioxide

North Carolina Global Case	*Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC*
NOx	Nitrogen oxides
NRC	Nuclear Regulatory Commission
O&M	Operation and maintenance expense
OATT	Open Access Transmission Tariff
OCI	Other comprehensive income
Ongoing Earnings	Non-GAAP financial measure defined as GAAP net income attributable to controlling interests after excluding discontinued operations and the effects of certain identified gains and charges
OPEB	Postretirement benefits other than pensions
ORS	South Carolina Office of Regulatory Staff
the Parent	Progress Energy, Inc. holding company on an unconsolidated basis
PEC	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.
PEF	Florida Power Corporation d/b/a Progress Energy Florida, Inc.
PESC	Progress Energy Service Company, LLC
Power Agency	North Carolina Eastern Municipal Power Agency
PPACA	Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act
Preferred Securities	7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A issued by the Trust
Preferred Securities Guarantee	Florida Progress' guarantee of all distributions related to the Preferred Securities
Progress Affiliates	Five affiliated coal-based solid synthetic fuels facilities
Progress Energy	Progress Energy, Inc. and subsidiaries on a consolidated basis
Progress Registrants	The reporting registrants within the Progress Energy consolidated group. Collectively, Progress Energy, Inc., PEC and PEF
PRP	Potentially responsible party, as defined in CERCLA
PSSP	Performance Share Sub-Plan
QF	Qualifying facility
RCA	Revolving credit agreement
Reagents	Commodities such as ammonia and limestone used in emissions control technologies
REPS	Renewable energy portfolio standard
the Registration Statement	The registration statement filed on Form S-4 by Duke Energy related to the Merger
Robinson	PEC's Robinson Nuclear Plant
ROE	Return on equity
RSU	Restricted stock unit
SCPSC	Public Service Commission of South Carolina
Section 29	Section 29 of the Code
Section 29/45K	General business tax credits earned after December 31, 2005 for synthetic fuels production in accordance with Section 29
Section 45K	Section 45K of the Code
Section 316(b)	Section 316(b) of the Clean Water Act
(See Note/s "#")	For all sections, this is a cross-reference to the Combined Notes to the Financial Statements contained in PART II, Item 8 of this Form 10-K
SERC	SERC Reliability Corporation
S&P	Standard & Poor's Rating Services
SO_2	Sulfur dioxide

SOx	Sulfur oxides
Subordinated Notes	7.10% Junior Subordinated Deferrable Interest Notes due 2039 issued by Funding Corp.
Tax Agreement	Intercompany Income Tax Allocation Agreement
the Trust	FPC Capital I
the Utilities	Collectively, PEC and PEF
VSP	Voluntary severance plan
VIE	Variable interest entity
Ward	Ward Transformer site located in Raleigh, N.C.
Ward OU1	Operable unit for stream segments downstream from the Ward site
Ward OU2	Operable unit for further investigation at the Ward facility and certain adjacent areas

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

In this combined report, each of the Progress Registrants makes forward-looking statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The matters discussed throughout this combined 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. 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 the Progress Registrants undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

In addition, examples of forward-looking statements discussed in this Form 10-K include, but are not limited to, 1) statements made in PART I, Item 1A, "Risk Factors" and 2) PART II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" (MD&A) including, but not limited to, statements under the following headings: a) "Merger" about the proposed merger between Progress Energy and Duke Energy Corporation (Duke Energy) (the Merger) and the impact of the Merger on our strategy and liquidity; b) "Strategy" about our future strategy and goals; c) "Results of Operations" about trends and uncertainties; d) "Liquidity and Capital Resources" about operating cash flows, future liquidity requirements and estimated capital expenditures; and e) "Other Matters" about the effects of new environmental regulations, changes in the regulatory environment, meeting anticipated demand in our regulated service territories, potential nuclear construction and our synthetic fuels tax credits.

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:

- our ability to obtain the approvals required to complete the Merger and the impact of compliance with material restrictions or conditions potentially imposed by our regulators;
- the risk that the Merger is terminated prior to completion and results in significant transaction costs to us;
- our ability to achieve the anticipated results and benefits of the Merger;
- the impact of business uncertainties and contractual restrictions while the Merger is pending;
- the scope of necessary repairs of the delamination of PEF's Crystal River Unit No. 3 Nuclear Plant (CR3) could prove more extensive than is currently identified, such repairs could prove not to be feasible, the costs of repair and/or replacement power could exceed our estimates and insurance coverage or may not be recoverable through the regulatory process;
- the impact of fluid and complex laws and regulations, including those relating to the environment and energy policy;
- our ability to recover eligible costs and earn an adequate return on investment through the regulatory process;
- the ability to successfully operate electric generating facilities and deliver electricity to customers;
- the impact on our facilities and businesses from a terrorist attack, cyber security threats and other catastrophic events;
- the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks;
- our ability to meet current and future renewable energy requirements;
- the inherent risks associated with the operation and potential construction of nuclear facilities, including environmental, health, safety, regulatory and financial risks;
- the financial resources and capital needed to comply with environmental laws and regulations;
- risks associated with climate change;
- weather and drought conditions that directly influence the production, delivery and demand for electricity;
- recurring seasonal fluctuations in demand for electricity;
- the ability to recover in a timely manner, if at all, costs associated with future significant weather events through the regulatory process;
- fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process;
- the Progress Registrants' ability to control costs, including operations and maintenance expense (O&M) and large construction projects;

- the ability of our subsidiaries to pay upstream dividends or distributions to Progress Energy, Inc. holding company (the Parent);
- current economic conditions;
- the ability to successfully access capital markets on favorable terms;
- the stability of commercial credit markets and our access to short- and long-term credit;
- the impact that increases in leverage or reductions in cash flow may have on each of the Progress Registrants;
- the Progress Registrants' ability to maintain their current credit ratings and the impacts in the event their credit ratings are downgraded;
- the investment performance of our nuclear decommissioning trust (NDT) funds;
- the investment performance of the assets of our pension and benefit plans and resulting impact on future funding requirements;
- the impact of potential goodwill impairments;
- our ability to fully utilize tax credits generated from the previous production and sale of qualifying synthetic fuels under Internal Revenue Code Section 29/45K (Section 29/45K); and
- the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements.

Many of these risks similarly impact our nonreporting subsidiaries.

These and other risk factors are detailed from time to time in the Progress Registrants' filings with the SEC. Many, but not all, of the factors that may impact actual results are discussed in Item 1A, "Risk Factors," which should be read carefully. All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond our control. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can management assess the effect of each such factor on the Progress Registrants.

PART I

ITEM 1. BUSINESS

GENERAL

ORGANIZATION

Progress Energy, Inc. is a public utility holding company primarily engaged in the regulated electric utility business. Headquartered in Raleigh, N.C., it owns, directly or indirectly, all of the outstanding common stock of its utility subsidiaries, PEC and PEF. In this report, Progress Energy, which includes the Parent and its subsidiaries on a consolidated basis, is at times referred to as "we," "our" or "us." When discussing Progress Energy's financial information, it necessarily includes the results of PEC and PEF (collectively, the Utilities). The term "Progress Registrants" refers to each of the three separate registrants: Progress Energy, PEC and PEF. However, neither of the Utilities makes any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself. The Parent was incorporated on August 19, 1999, initially as CP&L Energy, Inc. and became the holding company for PEC on June 19, 2000. We acquired PEF through our November 2000 acquisition of its parent, Florida Progress Corporation (Florida Progress).

Our reportable segments are PEC and PEF, which are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. The Corporate and Other segment primarily includes amounts applicable to the activities of the Parent and Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable business segment. See Note 20 for information regarding the revenues, income and assets attributable to our business segments.

The Utilities have 23,000 megawatts (MW) of regulated electric generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities. We are dedicated to meeting the growth needs of our service territories and delivering reliable, competitively priced energy from a diverse portfolio of power plants. The Utilities operate in retail service territories that have historically had population growth higher than the U.S. average. However, like other parts of the United States, our service territories and business have been negatively impacted by the current economic conditions. The timing and extent of the recovery of the economy cannot be predicted.

For the year ended December 31, 2011, our consolidated revenues were $8.907 billion and our consolidated assets at year-end were $35.059 billion.

The Progress Registrants' annual reports on Form 10-K, definitive proxy statements for our annual shareholder meetings, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports are available free of charge through the Investor Relations section of our website at www.progress-energy.com. Information on our website is not incorporated herein and should not be deemed part of this Report. These reports are available as soon as reasonably practicable after such material is electronically filed with, or furnished with, the SEC. The public may read and copy any material we have filed with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information regarding the operations of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. Alternatively, the SEC maintains a website, www.sec.gov, containing reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

RECENT DEVELOPMENTS

On January 8, 2011, Duke Energy and Progress Energy entered into an Agreement and Plan of Merger (the Merger Agreement), which expires on July 8, 2012. Pursuant to the Merger Agreement, Progress Energy will be acquired by Duke Energy in a stock-for-stock transaction and become a wholly owned subsidiary of Duke Energy (the Merger). Both companies' shareholders have approved the Merger. However, consummation of the Merger is subject to customary conditions, including, among other things, expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and receipt of approval, to the extent required, from the Federal Energy Regulatory Commission

(FERC), the Federal Communications Commission, the Nuclear Regulatory Commission (NRC), the North Carolina Utilities Commission (NCUC), the Kentucky Public Service Commission and the South Carolina Public Service Commission (SCPSC). Although there are no merger-specific regulatory approvals required in Indiana, Ohio or Florida, the companies will continue to update the public service commissions in those states on the Merger, as applicable and as required. See Item IA, "Risk Factors," MD&A – "Introduction – Merger," and Note 2 for additional information related to the Merger.

On February 22, 2012, the Florida Public Service Commission (FPSC) approved a comprehensive settlement agreement between PEF, the Florida Office of Public Counsel and other consumer advocates. The agreement, which will continue through the last billing cycle of December 2016, addresses three principal matters: cost recovery for PEF's proposed Levy Nuclear Power Plant (Levy), the CR3 delamination prudence review pending before the FPSC and certain base rate issues. The agreement sets the Levy cost-recovery factor at a fixed amount during the term of the settlement and also allows PEF to recover investment and replacement power costs for CR3 in various circumstances. The parties to the agreement have waived or limited their rights to challenge the prudence of various costs related to CR3. The agreement provides for a $150 million annual increase in revenue requirements effective with the first billing cycle of January 2013, while maintaining the current return on equity (ROE) range of 9.5 percent to 11.5 percent. In the month following CR3's return to commercial service, PEF's ROE range will increase to 9.7 percent to 11.7 percent. Additionally, PEF will refund $288 million to customers through the fuel clause over four years, beginning in 2013. See Note 8C for additional provisions of the 2012 settlement agreement.

In September 2009, CR3 began an outage for normal refueling and maintenance as well as an uprate project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination (or separation) within the concrete of the outer wall of the containment building, which resulted in an extension of the outage. In March 2011, engineers investigated and subsequently determined that a new delamination had occurred in another area of the structure after initial repair work was completed and during the late stages of retensioning the containment building. Subsequent to March 2011, monitoring equipment has detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations could occur during the repair process. Engineering design of the repair is under way. A number of factors could affect the repair plan, the return-to-service date and costs, including regulatory reviews, final engineering designs, contract negotiations, the ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis and other developments. See "Nuclear Matters – CR3 Outage" and Note 8C.

COMPETITION

RETAIL COMPETITION

To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give the Utilities' retail customers the right to choose their electricity provider or otherwise restructure or deregulate the electric industry. However, the Utilities compete with suppliers of other forms of energy in connection with their retail customers.

Although there is no pending legislation at this time, if the retail jurisdictions served by the Utilities become subject to deregulation, the recovery of "stranded costs" could become a significant consideration. 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 qualified facilities (QFs). Thus far, all states that have passed restructuring legislation have provided for the opportunity to recover a substantial portion of stranded costs.

Our largest stranded cost exposure is for PEF's purchased power commitments with QFs, under which PEF has future minimum expected capacity payments through 2025 of $4.1 billion (See Notes 22A and 22B). PEF was obligated to enter into these contracts under provisions of the Public Utilities Regulatory Policies Act of 1978. PEF continues to seek ways to address the impact of escalating payments under these contracts. However, the FPSC allows full recovery of the retail portion of the cost of power purchased from QFs. PEC does not have significant future minimum expected capacity payments under its purchased power commitments with QFs.

WHOLESALE COMPETITION

The Utilities compete with other utilities and merchant generators for bulk power sales and for sales to municipalities and cooperatives.

Increased competition in the wholesale electric utility industry and the availability of transmission access could affect the Utilities' load forecasts, plans for power supply and wholesale energy sales and related revenues. Wholesale energy sales will be impacted by the extent to which additional generation is available to sell to the wholesale market and the ability of the Utilities to attract new wholesale customers and to retain current wholesale customers who have existing contracts with PEC or PEF.

PEC and PEF are subject to regulation by the FERC with respect to transmission service, including generator interconnection service for facilities making sales for resale and wholesale sales of electric energy.

In February 2007, the FERC adopted final rules making extensive changes to the pro forma open access transmission tariff (OATT) to ensure that transmission service is provided in a fair manner to all transmission customers. PEC's and PEF's compliance filings reflecting the required changes in the transmission planning areas were approved by the FERC in 2010. Although this final rule impacted the Utilities' transmission operations, planning and wholesale marketing functions, it did not have a significant impact on the Utilities' financial results.

In July 2011, the FERC adopted additional final rules related to regional and interregional transmission planning and cost allocation. These rules also require that the transmission planning process provides a structure whereby a non-incumbent transmission developer could be considered for building transmission projects that are selected for regional or interregional cost allocation. Public utility transmission providers are required to submit compliance filings addressing the regional requirements of the rule by October 2012 and are required to submit compliance filings addressing the interregional requirements of the rule by April 2013. The rule will require significant changes in the PEC and PEF regional and interregional transmission planning and cost allocation approaches, however, based on a preliminary assessment of the rule, it is not expected to have a significant impact on the Utilities' financial results.

The FERC requires that entities desiring to make wholesale sales of electricity at market-based rates document that they do not possess market power. Market power is exercised when an entity profitably drives up prices through its control of a single activity, such as electricity generation, where it controls a significant share of the total capacity available to the market. The FERC has established screening measures for such determinations. Given the difficulty PEC believed it would experience in passing one of the screens, PEC revised its market-based rate tariffs in 2005 to restrict PEC to making market-based sales outside of its control area and peninsular Florida, and filed a new cost-based tariff for sales within PEC's control area. PEF likewise made comparable filings which restrict PEF to making market-based rates outside of peninsular Florida and outside of the PEC control area. Accordingly, PEC and PEF make wholesale sales of electricity at cost-based rates in areas inside of PEC's control area and peninsular Florida, and at market-based rates outside of PEC's control area and peninsular Florida. We do not anticipate that the operations of the Utilities will be materially impacted by this market-based rate decision.

FRANCHISE MATTERS

PEC has non-exclusive franchises with varying expiration dates in most of the municipalities in North Carolina and South Carolina in which it distributes electricity. In North Carolina, franchises generally continue for 60 years. In South Carolina, franchises continue in perpetuity unless terminated according to certain statutory methods. 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 PEC's 240 franchises, the majority covers 60-year periods from the date enacted, and 45 have no specific expiration dates. Of the PEC franchise agreements with expiration dates, 11 expire during the period 2012 through 2016, and the remaining agreements expire between 2017 and 2071. We anticipate renewing substantially all of the expiring franchise agreements. To the extent that PEC does not renew the expiring franchise agreements, PEC will continue to operate within municipal rights of way pursuant to statutory authority. PEC also provides service within a number of municipalities and in all of the unincorporated areas within its service area without franchise agreements.

PEF has non-exclusive franchises with varying expiration dates in 113 of the Florida municipalities in which it distributes electricity. PEF also provides service to eight other municipalities and in all of the unincorporated areas within its service area without franchise agreements. The general effect 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. The PEF franchise agreements cover periods ranging from 10- to 30-year periods from the date enacted. Of PEF's 113 franchise agreements, 25 expire between 2012 and 2016, and the remaining agreements expire between 2017 and 2040. We anticipate renewing substantially all of the expiring franchise agreements. To the extent that PEF does not renew the expiring franchise agreements, PEF will continue to operate within municipal rights of way in compliance with city permitting processes that govern these activities.

REGULATORY MATTERS

HOLDING COMPANY REGULATION

The Parent is a registered public utility holding company subject to regulation by the FERC, including provisions relating to the establishment of intercompany extensions of credit, sales, acquisitions of securities and utility assets, and services performed by PESC. The FERC also has authority over accounting and record retention and cost allocation jurisdiction at the election of the holding company system or the state utility commissions with jurisdiction over its utility subsidiaries.

UTILITY REGULATION

FEDERAL REGULATION

The Utilities are subject to regulation by a number of federal regulatory agencies, including the United States Department of Energy (DOE), the North American Electric Reliability Corporation (NERC), the NRC and the United States Environmental Protection Agency (EPA).

Reliability Standards

The FERC has certified the NERC as the electric reliability organization that will propose and enforce mandatory reliability standards for the bulk power electric system. Included in this certification was a provision for the delegation of authority to audit, investigate and enforce reliability standards in particular regions of the country by entering into delegation agreements with regional entities. In addition, the regional entities have the ability to formulate additional reliability standards in their respective regions, which are required to supplement and be more stringent than the NERC reliability standards. The SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council are the regional entities for PEC and PEF, respectively.

PEC and PEF are currently subject to certain reliability standards as registered users, owners and operators of the bulk power electric system. We expect existing reliability standards to migrate to more definitive and enforceable requirements over time and additional NERC and regional reliability standards to be approved by the FERC in coming years requiring us to take additional steps to remain compliant. The financial impact of mandatory compliance cannot currently be determined. Failure to comply with the reliability standards could result in the imposition of fines and civil penalties. If we are unable to meet the reliability standards for the bulk power electric system in the future, it could have a material adverse effect on our financial condition, results of operations and liquidity.

PEC and PEF have self-reported to the SERC and Florida Reliability Coordinating Council, respectively, noncompliances and violations with the voluntary and mandatory standards from time to time. The noncompliances and violations have led to the development and implementation of mitigation plans at the Utilities. None of the noncompliances or violations noted above nor the costs of executing the mitigation plans are expected to have a significant impact on our overall compliance efforts, results of operations or liquidity.

Nuclear Regulation

The Utilities' nuclear generating units are regulated by the NRC. The NRC is responsible for granting licenses for the construction, operation and retirement of nuclear power plants and subjects these plants to continuing review and regulation. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit or take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved. See "Nuclear Matters."

Environmental Regulation

The Utilities are also subject to regulation by federal, state and local regulatory agencies. See "Environmental."

STATE REGULATION

PEC is subject to regulation in North Carolina by the NCUC, and in South Carolina by the SCPSC. PEF is subject to regulation in Florida by the FPSC. The Utilities are regulated by their respective regulatory bodies with respect to, among other things, rates and service for electricity sold at retail; retail cost recovery of unusual or unexpected expenses, such as severe storm costs; and issuances of securities. 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 earn a reasonable rate of return on its invested capital, including equity.

Retail Rate Matters

Each of the Utilities' state utility commissions authorizes retail "base rates" that are designed to provide the respective utility with the opportunity to earn a reasonable rate of return on its "rate base," or net investment in utility plant. These rates are intended to cover all reasonable and prudent expenses of constructing, operating and maintaining the utility system, except those covered by specific cost-recovery clauses.

In PEC's most recent rate cases in 1988, the NCUC and the SCPSC each authorized a ROE of 12.75 percent.

In PEF's 2010 settlement agreement approved by the FPSC, the FPSC authorized PEF the opportunity to earn a ROE of up to 11.5 percent. The 2010 settlement agreement is in effect through the last billing cycle of 2012. See "Recent Developments" for discussion regarding the 2012 settlement agreement.

Retail Cost-Recovery Clauses

Each of the Utilities' state utility commissions allows recovery of certain costs through various cost-recovery clauses, to the extent the respective commission determines in an annual hearing that such costs, including any past over- or under-recovered costs, are prudent. The clauses are in addition to the Utilities' approved base rates. The Utilities generally do not earn a return on the recovery of eligible operating expenses under such clauses; however, in certain jurisdictions, the Utilities may earn interest on under-recovered costs. Additionally, the commissions may authorize a return for specified investments for energy efficiency and conservation, capacity costs, environmental compliance and utility plant. See MD&A – "Regulatory Matters and Recovery of Costs" for additional discussion regarding cost-recovery clauses.

Costs recovered by the Utilities through cost-recovery clauses, by retail jurisdiction, are as follows:

- *North Carolina Retail* – fuel costs, the fuel and other portions of purchased power (capacity costs for purchases from dispatchable QFs are also recoverable), costs of new demand-side management (DSM) and energy efficiency (EE) programs, costs of commodities such as ammonia and limestone used in emissions control technologies (Reagents), and eligible renewable energy costs;
- *South Carolina Retail* – fuel costs, certain purchased power costs, costs of Reagents, sulfur dioxide (SO_2) and nitrogen oxides (NOx) emission allowance expenses, and costs of new DSM and EE programs; and
- *Florida Retail* – fuel costs, purchased power costs, capacity costs, qualified nuclear costs, energy conservation expense and specified environmental costs, including Clean Air Interstate Rule (CAIR) compliance costs, and SO_2 and NOx emission allowance expenses.

Fuel, fuel-related costs and certain purchased power costs are eligible for recovery by the Utilities. The Utilities use coal, oil, hydroelectric (PEC only), natural gas and nuclear power to generate electricity, thereby maintaining a diverse fuel mix that helps mitigate the impact of cost increases in any one fuel. Due to the associated regulatory treatment and the method allowed for recovery, changes in fuel costs from year to year have no material impact on operating results of the Utilities, unless a commission finds a portion of such costs to have been imprudent. However, delays between the expenditure for fuel costs and recovery from ratepayers can adversely impact the timing of cash flow of the Utilities. PEF is obligated to file for a midcourse recovery between annual fuel hearings in the event its estimated over- or under-recovery of fuel costs meets or exceeds a threshold of 10 percent of estimated total retail fuel revenues and, accordingly, has the ability to mitigate the cash flow impacts due to the timing of recovery of fuel and purchased power costs.

Renewable Energy and Energy-Efficiency Standards

PEC is allowed to recover the costs of DSM and EE programs in North Carolina and South Carolina through an annual DSM and EE clause in each jurisdiction. PEC is allowed to capitalize DSM and EE costs intended to produce future benefits. In addition, the NCUC and the SCPSC have approved other forms of financial incentives for DSM and EE programs, including the recovery of net lost revenues and a performance incentive. DSM programs include, but are not limited to, any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control, interruptible load and electric system equipment and operating controls. EE programs include any equipment, physical or program change implemented after January 1, 2007, that results in less energy used to perform the same function. PEC has implemented a series of DSM and EE programs and will continue to pursue additional programs, which must be approved by the respective utility commissions. We cannot predict the outcome of DSM and EE filings currently pending approval or whether the implemented programs will produce the expected operational and economic results.

PEC is subject to renewable energy standards at the state level in North Carolina. North Carolina’s Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) establishes minimum standards for the use of energy from specified renewable energy resources or implementation of energy-efficiency measures by the state’s electric utilities beginning with a 3 percent requirement in 2012 and increasing to 12.5 percent in 2021 for regulated public utilities, including PEC. PEC is on track to meet the 3 percent of retail electric sales target in 2012. PEC has worked diligently to meet the set aside requirements in NC REPS, however, our ability to do so is contingent upon developers meeting proposed project sizes and timelines. In the event that PEC is unable to meet any of the NC REPS set-aside requirements, PEC will seek to modify or delay the set-aside provisions as permitted by the NCUC. The premium to be paid by electric utilities to comply with the requirements above the cost they would have otherwise incurred to meet consumer demand is to be recovered through an annual clause. The annual amount that can be recovered through the NC REPS clause is capped and once a utility has expended monies equal to the cap, the utility is deemed to have met its obligations, regardless of the actual renewables generated or purchased. The NCUC has the authority to modify or alter the NC REPS requirements if the NCUC determines it is in the public interest to do so.

Florida energy law enacted in 2008 includes provisions for development of a renewable portfolio standard for Florida utilities. The Florida legislature has not taken action on a renewable portfolio standard rule. Until the rulemaking processes are completed, we cannot predict the costs of complying with the law, but PEF would be able to recover its reasonable and prudent compliance costs.

On July 26, 2011, the FPSC voted to set PEF’s DSM compliance goals to remain at their current level until the next goal setting docket is initiated. An intervener filed a protest to the FPSC’s Proposed Agency Action order, asserting legal challenges to the order. The parties made legal arguments to the FPSC and the FPSC issued an order denying the protest on December 22, 2011. The intervener then filed a notice of appeal of this order to the Florida Supreme Court on January 17, 2012. We cannot predict the outcome of this matter.

See Note 8 for further discussion of regulatory matters.

NUCLEAR MATTERS

GENERAL

The nuclear power industry faces uncertainties with respect to the cost and long-term availability of disposal sites for spent nuclear fuel and other radioactive waste, compliance with changing regulatory requirements, capital outlays for modifications and new plant construction, the technological and financial aspects of decommissioning plants at the end of their licensed lives, and requirements relating to nuclear insurance. Nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs, uprates and certain other modifications.

PEC owns and operates four nuclear generating units: Brunswick Nuclear Plant (Brunswick) Unit No. 1 and Unit No. 2, Shearon Harris Nuclear Plant (Harris) and Robinson Nuclear Plant (Robinson). The NRC has renewed the operating licenses for all of PEC's nuclear plants. The renewed operating licenses for Brunswick No. 1 and No. 2, Harris and Robinson expire in September 2036, December 2034, October 2046 and July 2030, respectively.

PEF owns and operates one nuclear generating unit, CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. On March 9, 2009, the NRC docketed, or accepted for review, PEF's application for a 20-year renewal on the operating license for CR3, which would extend the operating license through 2036, when approved. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will renew the license. The license renewal application for CR3 is currently under review by the NRC. The NRC's remaining open items in the license renewal review process are associated with the containment structure repair. Once the repair design has been completed and evaluated, the NRC may proceed with the renewal application review of the containment structure. Assuming the repair is successful, management believes CR3 will satisfy the requirements for the license renewal.

The NRC periodically issues bulletins and orders addressing industry issues of interest or concern that necessitate a response from the industry. It is our intent to comply with and to complete required responses in a safe, timely and accurate manner. Any potential impact to company operations could vary and would be dependent upon the nature of the requirement(s).

CR3 OUTAGE

Over time, PEC and PEF have made various modifications to their nuclear facilities to increase the energy output. During CR3's fueling and maintenance outage that began in September 2009, PEF commenced a project to replace CR3's steam generators. During preparations to replace the steam generators, workers discovered a delamination (or separation) within the concrete of the outer wall of the containment building, which resulted in an extension of the outage. In March 2011, engineers investigated and subsequently determined that a new delamination had occurred in another area of the structure after initial repair work was completed and during the late stages of retensioning the containment building. Subsequent to March 2011, monitoring equipment detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations could occur during the repair process. Engineering design of the repair is under way. The preliminary cost estimate for the repair, as filed with the FPSC on June 27, 2011, is between $900 million and $1.3 billion. PEF will update the current estimate as this work is completed. Under this repair plan, we estimate CR3 will return to service in 2014. Nuclear safety remains our top priority, and our plans and actions will continue to reflect that commitment. The decision related to repairing or decommissioning CR3 is complex and subject to a number of unknown factors, including but not limited to the cost of repair and the likelihood of obtaining NRC approval to restart CR3 after repair. A number of factors could affect the repair plan, the return-to-service date and costs, including regulatory reviews, final engineering designs, contract negotiations, the ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis, and other developments. PEF maintains insurance coverage through the Nuclear Electric Insurance Limited's (NEIL) accidental property damage program, and PEF is continuing to work with NEIL for recovery of applicable repair costs and associated replacement power costs. See Note 8C.

POTENTIAL NEW CONSTRUCTION

While we have not made a final determination on new nuclear construction, we continue to take steps to keep open the option of building one or more plants. During 2008, PEC and PEF filed combined license (COL) applications to potentially construct new nuclear plants in North Carolina and Florida. The NRC estimates that it will take approximately three to four years to review and process the COL applications. We have focused on PEF's potential construction at Levy given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce greenhouse gas (GHG) emissions as well as existing state legislative policy that is supportive of nuclear projects.

LEVY

In 2006, we announced that PEF selected a greenfield site at Levy to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs.

In 2008, the FPSC issued a final order granting PEF's petition for a Determination of Need for Levy. In 2009, the Power Plant Siting Board, comprised of the governor and the Cabinet, issued the Levy site certification that addresses permitting, land use and zoning, and property interests and replaces state and local permits. Certification grants approval for the location of the power plant and its associated facilities such as roadways and electrical transmission lines carrying power to the electrical grid, among others. Certification does not include licenses required by the federal government.

On July 30, 2008, PEF filed its COL application with the NRC for two reactors, which was docketed, or accepted for review, by the NRC on October 6, 2008. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. The NRC review and development of the Final Safety Evaluation Report and Final Environmental Impact Statement is expected to be complete in April 2012, which will be followed by mandatory and contested hearings. One joint petition to intervene in the licensing proceeding was filed with the NRC within the 60-day notice period by the Green Party of Florida, the Nuclear Information and Resource Service and the Ecology Party of Florida. The Atomic Safety and Licensing Board (ASLB) admitted one contention regarding potential impacts to wetlands from groundwater use and the potential impact of salt drift from cooling tower operation. Under the current schedule, mandatory and contested hearings are expected to be complete by late 2012, with a combined license issued in 2013. We cannot predict the outcome of this matter.

PEF also completed and submitted a Limited Work Authorization request for Levy concurrent with the COL application. PEF's initial schedule anticipated performing certain site work pursuant to the Limited Work Authorization prior to COL receipt. However, in 2009, the NRC Staff determined that certain schedule-critical work that PEF had proposed to perform within the scope of the Limited Work Authorization will not be authorized until the NRC issues the COL. Consequently, excavation and foundation preparation work will be shifted until after COL issuance. This factor alone resulted in a minimum 20-month schedule shift later than the projected in-service dates for Units No. 1 and No. 2 of June 2016 and June 2017, respectively, included in the petition for a Determination of Need. Subsequent changes in regulatory and economic conditions have resulted in additional schedule shifts. These conditions include the permitting and licensing process, national and state economic conditions, short-term natural gas prices, and other FPSC decisions. Uncertainty regarding PEF's access to capital on reasonable terms, its ability to secure joint owners and increasing uncertainty surrounding carbon regulation and its costs could be other factors to affect the Levy schedule.

As disclosed in PEF's 2011 nuclear cost-recovery filing, the schedule shifts will reduce the near-term capital expenditures for the project and also reduce the near-term impact on customer rates (See Note 8C). PEF will postpone major construction activities on the project until after the NRC issues the COL, which is expected to be in 2013 if the current licensing schedule remains on track. The schedule shifts will also allow more time for certainty around federal climate change policy. We believe that continuing, although at a slower pace than initially anticipated, is a reasonable and prudent course at this early stage of the project. Taking into account cost, potential carbon regulation, fossil fuel price volatility and the benefits of fuel diversification, we consider Levy to be PEF's preferred baseload generation option. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including, but not limited to, public, regulatory and political support; adequate financial cost-recovery mechanisms; adequate levels of joint owner participation; customer rate impacts; project feasibility, including comparison to other generation options, DSM and EE programs; and availability and terms of capital financing. If the licensing schedule remains on track and if the decision to build is made, the first of the two proposed units could be in service in 2021. The second unit could be in service 18 months later.

PEF signed an engineering, procurement and construction (EPC) agreement on December 31, 2008, with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two Westinghouse AP1000 nuclear units to be constructed at Levy. More than half of the approximate $7.650 billion contract price is fixed or firm with agreed upon escalation factors. The EPC agreement includes various incentives, warranties, performance guarantees, liquidated damage provisions and parent guarantees designed to incent the contractor to perform efficiently. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. PEF executed an amendment to the EPC agreement in 2010 due to the schedule shifts previously discussed. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF completed vendor negotiations in July 2011 to continue or suspend purchase orders for long lead time equipment without material fees or charges.

The total escalated cost for the two generating units was estimated in PEF's petition for the Determination of Need for Levy to be approximately $14 billion. This total cost estimate included land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. An additional $3 billion was estimated for the necessary transmission equipment and approximately 200 miles of transmission lines associated with the project. PEF's 2011 nuclear cost-recovery filing included an updated analysis that demonstrated continued feasibility of the Levy project with PEF's then estimated range of total escalated cost, including transmission, of $17.2 billion to $22.5 billion. The filed estimated cost range primarily reflects cost escalation resulting from the schedule shifts. Many factors will affect the total cost of the project and once PEF receives the COL, it will further refine the project timeline and budget. As previously discussed, we will continue to evaluate the Levy project on an ongoing basis.

Florida regulations allow investor-owned utilities such as PEF to recover the retail portion of prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balances of a nuclear power plant prior to commercial operation. The costs are recovered on an annual basis through the Capacity Cost-Recovery Clause (CCRC). Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after the utility receives a final order granting a Determination of Need. These costs include any unrecovered retail portion of construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. In addition, the rule requires the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility (See Note 8C).

HARRIS

In 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC's application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris, which the NRC docketed on April 17, 2008. No petitions to intervene have been admitted in the Harris COL application. If we receive approval from the NRC and applicable state agencies, and if the decision to build is made, a new plant would not be online until the middle of the next decade.

PEC's jurisdictions also have laws regarding nuclear baseload generation. South Carolina law includes provisions for cost-recovery mechanisms associated with nuclear baseload generation. North Carolina law authorizes the NCUC to allow annual prudence reviews of baseload generating plant construction costs and inclusion of construction work in progress in rate base with corresponding rate adjustment in a general rate case while a baseload generating plant is under construction.

SECURITY

The NRC issues orders with regard to security at nuclear plants in response to new or emerging threats. The most recent orders include additional restrictions on nuclear plant access, increased security measures at nuclear facilities and closer coordination with our partners in intelligence, military, law enforcement and emergency response at the federal, state and local levels. We are in compliance with the requirements outlined in the orders through the use of additional security measures until permanent construction projects are completed in 2012. 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 NUCLEAR FUEL

The Nuclear Waste Policy Act of 1982 (as amended) 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 Policy Act of 1982 promotes increased usage of interim storage of spent nuclear fuel at existing nuclear plants. We will continue to maximize the use of spent fuel storage capability within our own facilities for as long as feasible.

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. We have contracts with the DOE for the future storage and disposal of our spent nuclear fuel. Delays have occurred in the DOE's proposed permanent repository to be located at Yucca Mountain, Nev. See Note 22C for information about complaints filed by the Utilities in the United States Court of Federal Claims against the DOE for its failure to fulfill its contractual obligation to receive spent fuel from nuclear plants. Failure to open Yucca Mountain or another facility would leave the DOE open to further claims by utilities.

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

DECOMMISSIONING

In the Utilities' retail jurisdictions, provisions for nuclear decommissioning costs are approved by the respective state utility commissions 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. A condition of the operating license for each unit requires an approved plan for decontamination and decommissioning. See Note 5C for a discussion of the Utilities' nuclear decommissioning costs.

ENVIRONMENTAL

GENERAL

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations. Environmental laws and regulations frequently change and the ultimate costs of compliance cannot be precisely estimated. The current estimated capital costs associated with compliance with pollution control laws and regulations that we expect to incur are included within MD&A – "Liquidity and Capital Resources – Capital Expenditures."

The foundation for Progress Energy's environmental leadership strategy begins with its environmental management system. Under the environmental management system, the Environmental, Health and Safety Performance Council, which is comprised of senior executives, provides overall strategic direction, guides corporate environmental policy, monitors environmental regulatory compliance and approves targets that measure, track and drive performance. Our environmental activities are reported to our board of directors' Operations and Nuclear Oversight Committee. The committee is responsible for climate change oversight and strategy and, therefore, assesses our plans and activities and makes recommendations to the full board regarding these matters. We have established a process to identify environmental risks, take prompt action to address these issues and ensure appropriate senior management oversight on a routine basis.

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 liability. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida or potentially responsible parties (PRP) groups. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 8 and 21). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted.

While we accrue for probable costs that can be reasonably estimated, based upon the current status of some sites, not all costs can be reasonably estimated or accrued and actual costs may materially exceed our accruals. Material costs in excess of our accruals could have an adverse impact on our financial condition and results of operations.

The EPA's final rule to regulate coal combustion residuals is expected in 2012. The EPA proposed two options in 2010. The first option would create a comprehensive program of federally enforceable requirements for coal combustion residual management and disposal as hazardous waste. The other option would have the EPA set mandatory performance standards for coal combustion residuals management facilities and regulate disposal of coal combustion residuals as nonhazardous waste (as most states do now). The EPA did not identify a preferred option. Under both options, the EPA may leave in place a regulatory exemption for approved beneficial uses of coal combustion residuals that are recycled. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized.

AIR QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which likely would result in increased capital expenditures and O&M expense. Control equipment installed for compliance with then-existing or proposed laws and regulations may address some of the issues outlined. PEC and PEF have been developing an integrated compliance strategy to meet these evolving requirements. PEC has installed environmental compliance controls that meet the emission reduction requirements under the first phase of the North Carolina Clean Smokestacks Act (Clean Smokestacks Act). The air quality controls installed to comply with NOx and SO_2 requirements under certain sections of the Clean Air Act and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, largely address the CAIR requirements for NOx and SO_2 for our North Carolina units at PEC. PEF has installed environmental compliance controls that meet the emission reduction requirements under the first phase of the CAIR.

In 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) and the maximum achievable control technology (MACT) standards for coal-fired and oil-fired electric steam generating units (EGU MACT). Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC and PEF are positioned to comply with the CSAPR without the need for significant capital expenditures, and PEC is relatively well positioned to comply with the EGU MACT. However, PEF will be required to complete additional emissions controls and/or fleet modernization projects in order to meet the compliance timeframe for the EGU MACT. The CSAPR, slated to be in effect January 1, 2012, was stayed by court order in late 2011. The final EGU MACT will become effective on April 16, 2012. Compliance is due in three years with provisions for a one-year extension from state agencies on a case-by-case basis. We are continuing to evaluate the impacts of the CSAPR and EGU MACT on the Utilities. We anticipate that compliance with the EGU MACT will satisfy the North Carolina mercury rule requirements for PEC.

WATER QUALITY

In 2011, the EPA published its proposed regulations for cooling water intake structures at existing power generating, manufacturing and industrial facilities that withdraw more than two million gallons of water per day from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes to comply with Section 316(b) of the Clean Water Act. Several of our generating plants will be subject to these regulations. The final rule is expected in 2012.

GLOBAL CLIMATE CHANGE

Global climate change is one of the primary corporate environmental risks identified by our environmental management system. Our risks associated with climate change are discussed under Item 1A, "Risk Factors."

Growing state, federal and international attention to global climate change may result in the regulation of carbon dioxide (CO_2) and other GHGs. The EPA has announced a schedule for development of a new source performance standard for new and existing fossil fuel-fired electric utility units. Under the schedule, the EPA was to propose the standard by September 30, 2011, and issue the final rule by May 2012. The EPA is now expected to propose the standard in the first quarter of 2012. The full impact of regulation under GHG initiatives and any final legislation, if enacted, cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time for which the Utilities would seek corresponding rate recovery.

As previously discussed under "Recent Developments," we are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. We are taking steps to address global climate change by changing the way we generate electricity through our balanced solution strategy. Our balanced solution as discussed in "Other Matters – Energy Demand" is a comprehensive plan to meet the anticipated demand in our service territories and provides a solid basis for slowing and reducing CO_2 emissions by focusing on energy efficiency, alternative energy and a state-of-the-art power system. We continuously evaluate new generation options to determine if they are cost effective for the Southeastern United States where our operations are located.

See Note 21 and MD&A – "Other Matters – Environmental Matters" for additional discussion of our environmental matters, including specific environmental issues, the status of the issues, accruals associated with issue resolutions and our associated exposures.

EMPLOYEES

At February 23, 2012, we employed approximately 11,000 full-time employees. Of this total, approximately 2,000 employees at PEF are represented by the International Brotherhood of Electrical Workers. We entered into a new one-year labor contract with the International Brotherhood of Electrical Workers beginning December 2011. We consider our relationship with employees, including those covered by collective bargaining agreements, to be good.

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

At February 23, 2012, PEC and PEF employed approximately 5,500 and 4,000 full-time employees, respectively.

SEASONALITY AND THE IMPACT OF WEATHER

Seasonal differences in the weather affect demand for electricity. The Utilities experience higher demand during the summer and winter months. As a result, our overall operating results may fluctuate substantially on a seasonal basis.

Beyond the impact of seasonality, deviations from normal weather conditions can significantly affect our financial performance. Our residential and commercial customers are most impacted by weather. Industrial customers are less weather sensitive. We define normal weather conditions as the long-term average of actual historical weather conditions. The number of years used to calculate normal weather is determined by management and differs by jurisdiction.

We estimate the impact of weather on our earnings based on the number of customers, temperature variances from a normal condition and the amount of electricity the average residential, commercial and some governmental customers historically demonstrated to use per degree day. Our methodology used to estimate the impact of weather does not and cannot consider all variables that may impact customer response to weather conditions such as humidity and relative temperature changes. The precision of this estimate may also be impacted by applying long-term weather trends to shorter periods.

Degree-day data are used to estimate the energy required to maintain comfortable indoor temperatures based on each day's average temperature. Heating-degree days measure the variation in the weather based on the extent to which the average daily temperature falls below a base temperature, and cooling-degree days measure the variation in weather based on the extent to which the average daily temperature rises above the base temperature. Each degree of temperature below the base temperature counts as one heating-degree day and each degree of temperature above the base temperature counts as one cooling-degree day. PEC's base temperature for heating- and cooling-degree days is 65° Fahrenheit for all customer classes. PEF's base temperatures vary by customer class, ranging from 65° to 70° Fahrenheit for cooling-degree days and 55° to 65° Fahrenheit for heating-degree days.

PEC

GENERAL

PEC is a regulated public utility founded in North Carolina in 1908 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North and South Carolina. At December 31, 2011, PEC had a total summer generating capacity (including jointly owned capacity) of 12,958 MW. For additional information about PEC's generating plants, see "Electric – PEC" in Item 2, "Properties." PEC's system normally experiences its highest peak demands during the summer, and the all-time system peak of 12,656 megawatt-hours (MWh) was set on August 9, 2007.

PEC's service territory covers approximately 34,000 square miles, including a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in western North Carolina in and around the city of Asheville and an area in the northeastern portion of South Carolina. At December 31, 2011, PEC was providing electric services, retail and wholesale, to approximately 1.5 million customers. Major wholesale power sales customers include North Carolina Electric Membership Corporation, North Carolina Eastern Municipal Power Agency (Power Agency) and Public Works Commission of the City of Fayetteville, North Carolina. Major industries in PEC's service area include chemicals, textiles, paper, food, metals, wood products, rubber and plastics and stone products. No single customer accounts for more than 10 percent of PEC's revenues.

PEC's net income available to parent was $513 million, $600 million and $513 million for the years ended December 31, 2011, 2010 and 2009, respectively. PEC's total assets were $16.102 billion, $14.899 billion and $13.502 billion at December 31, 2011, 2010 and 2009, respectively.

REVENUES

See "Electric Utility Regulated Operating Statistics – PEC" for information about energy sales and operating revenues.

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.

See "Electric Utility Regulated Operating Statistics – PEC" for generated and purchased energy supply by source and PEC's average fuel cost.

PEC's total system generation (excluding jointly owned capacity) by primary energy source, along with purchased power for the last three years, is presented in the following table:

	2011	2010	2009
Nuclear	**43%**	35%	41%
Coal	**35%**	49%	46%
Oil/Gas	**13%**	9%	6%
Purchased Power	**8%**	6%	6%
Hydro	**1%**	1%	1%

PEC is generally permitted to pass the cost of fuel and certain purchased power costs to its customers through fuel cost-recovery clauses. Because these costs are primarily recovered through recovery clauses established by regulators, fluctuations do not materially affect net income. 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 Item 1A, "Risk Factors." However, PEC believes that its fuel supply contracts, as described below and in Note 22A, will be adequate to meet its fuel supply needs.

<u>Nuclear</u>

Nuclear fuel is processed through four distinct stages: uranium ore mining and milling, conversion, enrichment and fabrication. PEC has sufficient contracts for each stage to meet its nuclear fuel requirement needs for the foreseeable future. PEC's nuclear fuel contracts typically have terms ranging from three to fifteen years. For a discussion of PEC's plans with respect to spent fuel storage, see "Nuclear Matters – Spent Nuclear Fuel."

<u>Coal</u>

PEC anticipates a burn requirement of approximately 9.6 million tons of coal in 2012. Approximately 88 percent of the coal is expected to be supplied from Central Appalachian, 7 percent from Illinois Basin, and 5 percent from Northern Appalachian coal sources and will be primarily delivered by rail.

For 2012, PEC has short-term, intermediate and long-term agreements from various sources for approximately 98 percent of its estimated burn requirements of its coal units. The contracts have expiration dates ranging from one to seven years. PEC will continue to sign contracts of various lengths, terms and quality to meet its expected burn requirements.

As discussed within Note 8B, PEC has implemented a plan to retire certain coal-fired units representing approximately 30 percent of its coal-fired power generation fleet no later than the end of 2013 as part of a major coal-to-gas modernization strategy. See "Oil and Gas" for planned gas facilities.

Oil and Gas

In June 2011, PEC placed in service a newly constructed 600-MW natural gas-fueled combined cycle unit at the Smith Energy Complex in Richmond County, N.C. PEC is in the process of constructing two new generating facilities: an approximately 950-MW combined cycle natural gas-fueled facility at a site in Wayne County, N.C., and an approximately 620-MW natural gas-fueled generating facility at its Sutton coal plant site in New Hanover County, N.C. The facilities have expected in-service dates in January 2013 and December 2013, respectively.

Oil and natural gas supply for PEC's generation fleet is purchased under term and spot contracts from various suppliers. PEC uses derivative instruments to limit its exposure to price fluctuations for natural gas. PEC has dual-fuel generating facilities that can operate with both oil and gas. The cost of PEC's physical oil and natural gas is either at a fixed price or 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 for its gas generation is purchased under term firm transportation contracts with interstate and intrastate pipelines. PEC may also purchase additional shorter-term transportation for its load requirements during peak periods.

Purchased Power

PEC purchased approximately 4.6 million MWh, 4.0 million MWh and 3.3 million MWh of its system energy requirements during 2011, 2010 and 2009, respectively, under purchase obligations and operating leases and had 1,394 MW of firm purchased capacity under contract during 2011. PEC may need to acquire additional purchased power capacity in the future to accommodate a portion of its system load needs. PEC believes that it can obtain adequate purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

Hydroelectric

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 summer generating capacity for all four units is 225 MW. PEC submitted an application to relicense its Tillery and Blewett plants for 50 years and anticipates a decision by the FERC in 2012. The Walters Plant license will expire in 2034.

PEF

GENERAL

PEF is a regulated public utility founded in Florida in 1899 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. At December 31, 2011, PEF had a total summer generating capacity (including jointly owned capacity) of 10,019 MW. For additional information about PEF's generating plants, see "Electric – PEF" in Item 2, "Properties." PEF's system normally experiences its highest peak demands during the winter, and the all-time system peak of 10,822 MWh was set on January 11, 2010.

PEF's service territory covers approximately 20,000 square miles in west-central Florida, and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 22 municipal and 9 rural electric cooperative systems. At December 31, 2011, PEF was providing electric services, retail and wholesale, to approximately 1.6 million customers. Major wholesale power sales customers include Seminole Electric Cooperative, Inc., Reedy Creek Improvement District, the city of Gainesville, the city of Winter Park and the city of Homestead. Major industries in PEF's territory include phosphate rock mining and processing, electronics design and manufacturing, and citrus and other food processing. Other major commercial activities are tourism, health care and agriculture. No single customer accounts for more than 10 percent of PEF's revenues.

PEF's net income available to parent was $312 million, $451 million and $460 million for the years ended December 31, 2011, 2010 and 2009, respectively. PEF's total assets were $14.484 billion, $14.056 billion and $13.100 billion at December 31, 2011, 2010 and 2009, respectively.

REVENUES

See "Electric Utility Regulated Operating Statistics – PEF" for information about energy sales and operating revenues.

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.

See "Electric Utility Regulated Operating Statistics – PEF" for PEF's energy supply by source and energy fuel cost.

PEF's total system generation (excluding jointly owned capacity) by primary energy source, along with purchased power for the last three years is presented in the following table:

	2011	2010	2009
Oil/Gas	**56%**	54%	44%
Coal	**25%**	26%	25%
Purchased Power	**19%**	20%	20%
Nuclear[a]	**-%**	-%	11%

[a]Due to the extended outage at CR3 nuclear generating unit that began in September 2009, no nuclear power was generated in 2011 and 2010.

PEF is generally permitted to pass the cost of fuel and certain purchased power to its customers through fuel cost-recovery clauses. Because these costs are primarily recovered through recovery clauses established by regulators, fluctuations do not materially affect net income. In early 2012, PEF agreed to a settlement returning $288 million to customers through the fuel clause (See Note 8C). 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 Item 1A, "Risk Factors." However, PEF believes that its fuel supply contracts, as described below and in Note 22A, will be adequate to meet its fuel supply needs.

Oil and Gas

Oil and natural gas supply for PEF's generation fleet is purchased under term and spot contracts from various suppliers. PEF uses derivative instruments to limit its exposure to price fluctuations for natural gas and oil. PEF has dual-fuel generating facilities that can operate with both oil and gas. The cost of PEF's physical oil and natural gas is either at a fixed price or 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 for its gas generation is purchased under term firm transportation contracts with interstate pipelines. PEF may also purchase additional shorter-term transportation for its load requirements during peak periods.

Coal

PEF anticipates a burn requirement of approximately 4.6 million tons of coal in 2012. Approximately 79 percent of the coal is expected to be supplied from the Illinois Basin and 21 percent from Central Appalachian coal sources and will be primarily delivered by water.

For 2012, PEF has intermediate and long-term contracts from various sources for approximately 105 percent of its estimated burn requirements of its coal units. These contracts have price adjustment provisions and have expiration dates ranging from one to four years. PEF will continue to sign contracts of various lengths, terms and quality to meet its expected burn requirements.

Purchased Power

PEF purchased approximately 7.8 million MWh, 9.5 million MWh and 8.7 million MWh of its system energy requirements during 2011, 2010 and 2009, respectively, under purchase obligations, operating leases and capital leases and had 2,105 MW of firm purchased capacity under contract during 2011. These agreements include approximately 682 MW of firm capacity under contract with certain QFs. PEF may need to acquire additional purchased power capacity in the future to accommodate a portion of its system load needs. PEF believes that it can obtain adequate purchased power to meet these needs if required. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

Nuclear

Nuclear fuel is processed through four distinct stages: uranium ore mining and milling, conversion, enrichment and fabrication. PEF has sufficient contracts for each stage to meet its nuclear fuel requirement needs for the foreseeable future. PEF's nuclear fuel contracts typically have terms ranging from three to fifteen years. For a discussion of PEF's plans with respect to spent fuel storage, see "Nuclear Matters – Spent Nuclear Fuel."

CORPORATE AND OTHER

Corporate and Other primarily includes the operations of the Parent and PESC. The Parent's unallocated interest expense is included in Corporate and Other. PESC provides centralized administrative, management and support services to our subsidiaries, which generates essentially all of the segment's revenues. See Note 19 for additional information about PESC services provided and costs allocated to subsidiaries. This segment also includes miscellaneous nonregulated business areas that do not separately meet the quantitative disclosure requirements as a reportable business segment.

The Corporate and Other segment's net loss attributable to controlling interests was $250 million, $195 million and $216 million for the years ended December 31, 2011, 2010 and 2009, respectively. Corporate and Other segment total assets were $20.926 billion, $21.110 billion and $20.538 billion at December 31, 2011, 2010 and 2009, respectively, which were primarily comprised of the Parent's investments in subsidiaries.

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PROGRESS ENERGY

	Years Ended December 31				
	2011	2010	2009	2008	2007
Energy supply (millions of kWh)					
Generated					
Steam	**33,834**	44,971	40,420	46,771	51,163
Nuclear	**25,059**	21,624	29,412	30,565	30,336
Combustion turbine/combined cycle	**29,259**	27,856	21,254	15,557	13,319
Hydro	**602**	608	651	429	415
Purchased	**12,404**	13,473	11,996	14,956	14,994
Total energy supply (company share)[a]	**101,158**	108,532	103,733	108,278	110,227
Jointly owned share[a] [b]	**5,046**	5,228	5,500	5,780	5,351
Total system energy supply	**106,204**	113,760	109,233	114,058	115,578
Average fuel costs (per million Btu)					
Oil	**$ 14.98**	$ 13.15	$ 11.78	$ 9.60	$ 8.70
Gas	**$ 6.24**	$ 6.92	$ 8.36	$ 10.14	$ 8.67
Coal	**$ 3.73**	$ 3.70	$ 3.85	$ 3.50	$ 3.06
Nuclear	**$ 0.60**	$ 0.59	$ 0.53	$ 0.46	$ 0.45
Weighted-average	**$ 3.55**	$ 3.90	$ 3.79	$ 3.66	$ 3.17
Energy sales (millions of kWh)					
Retail					
Residential	**37,386**	39,632	36,516	36,328	37,112
Commercial	**25,736**	26,080	25,523	26,080	26,215
Industrial	**13,856**	13,884	13,653	15,174	15,721
Other retail	**4,834**	4,860	4,753	4,768	4,805
Unbilled	**(1,226)**	630	491	(107)	(61)
Wholesale	**15,215**	17,856	17,801	21,063	21,333
Total energy sales	**95,801**	102,942	98,737	103,306	105,125
Company uses and losses	**5,357**	5,590	4,996	4,972	5,102
Total energy requirements	**101,158**	108,532	103,733	108,278	110,227
Operating revenues (in millions)					
Retail					
Billed	**$ 8,025**	$ 8,714	$ 8,449	$ 7,585	$ 7,672
Unbilled	**(58)**	28	14	7	1
Wholesale	**880**	1,080	1,114	1,288	1,191
Miscellaneous revenue	**338**	354	301	280	270
Amount to be refunded to customers[c]	**(288)**	-	-	-	-
Total operating revenues of the Utilities	**$ 8,897**	$ 10,176	$ 9,878	$ 9,160	$ 9,134

(a) The extended outage at PEF's CR3 nuclear generating unit that began in September 2009 impacted the energy supply mix in 2011, 2010 and 2009.

(b) Amounts represent joint owners' share of the energy supplied from the six generating facilities that are jointly owned. Replacement power was supplied to the CR3 joint owners in 2011 and 2010 from other generating sources or purchased power.

(c) Amount to be refunded to PEF customers through the fuel clause in accordance with the PEF 2012 settlement agreement (See Note 8C).

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PEC

	Years Ended December 31				
	2011	2010	2009	2008	2007
Energy supply (millions of kWh)					
Generated					
Steam	**21,009**	30,528	27,261	28,363	30,770
Nuclear	**25,059**	21,624	24,467	24,140	24,212
Combustion turbine/combined cycle	**7,435**	5,429	3,634	2,795	2,960
Hydro	**602**	608	651	429	415
Purchased	**4,512**	3,985	3,251	4,735	3,901
Total energy supply (company share)	**58,617**	62,174	59,264	60,462	62,258
Jointly owned share[(a)]	**5,046**	5,228	5,057	5,205	4,800
Total system energy supply	**63,663**	67,402	64,321	65,667	67,058
Average fuel costs (per million Btu)					
Oil	**$ 17.85**	$ 14.34	$ 14.84	$ 16.05	$ 12.28
Gas	**$ 5.98**	$ 6.59	$ 8.17	$ 10.66	$ 9.19
Coal	**$ 3.66**	$ 3.56	$ 3.82	$ 3.39	$ 2.96
Nuclear	**$ 0.60**	$ 0.59	$ 0.53	$ 0.46	$ 0.44
Weighted-average	**$ 2.48**	$ 2.69	$ 2.60	$ 2.44	$ 2.21
Energy sales (millions of kWh)					
Retail					
Residential	**18,148**	19,108	17,117	17,000	17,200
Commercial	**13,844**	14,184	13,639	13,941	14,032
Industrial	**10,613**	10,665	10,368	11,388	11,901
Other retail	**1,610**	1,574	1,497	1,466	1,438
Unbilled	**(597)**	172	360	(8)	(55)
Wholesale	**12,605**	13,999	13,966	14,329	15,309
Total energy sales	**56,223**	59,702	56,947	58,116	59,825
Company uses and losses	**2,394**	2,472	2,317	2,346	2,433
Total energy requirements	**58,617**	62,174	59,264	60,462	62,258
Operating revenues (in millions)					
Retail					
Billed	**$ 3,785**	$ 4,044	$ 3,801	$ 3,582	$ 3,534
Unbilled	**(34)**	11	5	8	-
Wholesale	**648**	729	707	737	754
Miscellaneous revenue	**129**	138	114	102	97
Total operating revenues	**$ 4,528**	$ 4,922	$ 4,627	$ 4,429	$ 4,385

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

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PEF

	Years Ended December 31				
	2011	2010	2009	2008	2007
Energy supply (millions of kWh)					
Generated					
Steam	**12,825**	14,443	13,159	18,408	20,393
Nuclear	**-**	-	4,945	6,425	6,124
Combustion turbine/combined cycle	**21,824**	22,427	17,620	12,762	10,359
Purchased	**7,892**	9,488	8,745	10,221	11,093
Total energy supply (company share)[(a)]	**42,541**	46,358	44,469	47,816	47,969
Jointly owned share[(a) (b)]	**-**	-	443	575	551
Total system energy supply	**42,541**	46,358	44,912	48,391	48,520
Average fuel costs (per million Btu)					
Oil	$ **14.11**	$ 12.96	$ 11.43	$ 9.24	$ 8.54
Gas	$ **6.33**	$ 7.00	$ 8.40	$ 10.03	$ 8.51
Coal	$ **3.88**	$ 4.09	$ 4.25	$ 3.74	$ 3.28
Nuclear	$ **-**	$ -	$ 0.52	$ 0.49	$ 0.48
Weighted-average	$ **5.53**	$ 6.14	$ 5.88	$ 5.67	$ 4.85
Energy sales (millions of kWh)					
Retail					
Residential	**19,238**	20,524	19,399	19,328	19,912
Commercial	**11,892**	11,896	11,884	12,139	12,183
Industrial	**3,243**	3,219	3,285	3,786	3,820
Other retail	**3,224**	3,286	3,256	3,302	3,367
Unbilled	**(629)**	458	131	(99)	(6)
Wholesale	**2,610**	3,857	3,835	6,734	6,024
Total energy sales	**39,578**	43,240	41,790	45,190	45,300
Company uses and losses	**2,963**	3,118	2,679	2,626	2,669
Total energy requirements	**42,541**	46,358	44,469	47,816	47,969
Operating revenues (in millions)					
Retail					
Billed	$ **4,240**	$ 4,670	$ 4,648	$ 4,003	$ 4,138
Unbilled	**(24)**	17	9	(1)	1
Wholesale	**232**	351	407	551	437
Miscellaneous revenue	**209**	216	187	178	173
Amount to be refunded to customers[(c)]	**(288)**	-	-	-	-
Total operating revenues	$ **4,369**	$ 5,254	$ 5,251	$ 4,731	$ 4,749

(a) The extended outage at PEF's CR3 nuclear generating unit that began in September 2009 impacted the energy supply mix in 2011, 2010 and 2009.

(b) Amounts represent joint owners' share of the energy supplied from the two generating facilities that are jointly owned. Replacement power was supplied to the CR3 joint owners in 2011 and 2010 from other generation sources or purchased power.

(c) Amount to be refunded to customers through the fuel clause in accordance with the 2012 settlement agreement (See Note 8C).

ITEM 1A. RISK FACTORS

Investing in the securities of the Progress Registrants involves risks, including the risks described below, that could affect the Progress Registrants and their businesses, as well as the energy industry in general. Most of the business information, as well as the financial and operational data contained in our risk factors, is updated periodically in the reports the Progress Registrants file with the SEC. Before purchasing securities of the Progress Registrants, you should carefully consider the following risks and the other information in this combined Annual Report, as well as the documents the Progress Registrants file with the SEC from time to time. Each of the risks described below could result in a decrease in the value of the securities of the Progress Registrants and your investment therein.

Solely with respect to this Item 1A, "Risk Factors," unless the context otherwise requires or the disclosure otherwise indicates, references to "we," "us" or "our" are to each of the individual Progress Registrants, and the matters discussed are generally applicable to each Progress Registrant.

We may be unable to obtain the approvals required to complete our merger with Duke Energy or, obtaining required governmental and regulatory approvals may require the combined company to comply with restrictions or conditions that may materially impact the anticipated benefits of the Merger.

On January 8, 2011, we entered into a definitive merger agreement with Duke Energy. Before the Merger may be completed, various filings must be made with certain state and federal regulators, antitrust and other authorities in the United States. See Note 2 for the status of shareholder and regulatory approvals. These governmental authorities may impose conditions on the completion, or require changes to the terms, of the Merger, including restrictions or conditions on the business, operations or financial performance of the combined company following consummation that may materially impact the anticipated benefits of the Merger. These conditions or changes could have the effect of delaying completion of the Merger or imposing additional costs on or limiting the revenues of the combined company following the Merger, which could have a material adverse effect on the financial results of the combined company and/or cause either party to abandon the Merger.

In particular, in response to the FERC's concerns about market power in the Carolinas, we and Duke Energy have prepared a mitigation plan and anticipate filing it with the FERC after review by the NCUC. The mitigation plan contains an interim component involving power sales to new market participants and a permanent component involving construction of transmission upgrades. The companies intend to hold discussions with consumer advocates in an effort to reach agreement concerning state ratemaking treatment associated with the mitigation plan and other merger-related issues. We cannot provide assurances that the FERC will approve the mitigation plan or that the NCUC or SCPSC will approve ratemaking treatment of the components of the plan and other merger-related issues, in each case on terms acceptable to either company. In addition, the companies will have to assess the costs associated with any mitigation plan together with the costs associated with other regulatory approvals in connection with the provisions of the Merger Agreement.

We are also subject to the risk that other required conditions to the Merger may not be satisfied. The Merger is subject to a number of customary closing conditions, including the accuracy of representations and warranties, receipt of legal opinions concerning tax consequences, the absence of legal restraints, and the absence of any material adverse effect with respect to either party. In the event one of these conditions is not satisfied, one or both companies would have the ability to terminate the Merger unless satisfaction of the condition is waived.

In the event that the Merger Agreement is terminated prior to the completion of the Merger, we could incur significant transaction costs that could materially impact our financial performance and results. Failure to complete the Merger could also negatively impact our stock price and our future business and financial results.

We have incurred, and will continue to incur, significant merger transaction costs, including legal, accounting, financial advisory, filing, printing and other costs relating to the Merger. If the Merger is not completed, then the benefit of these costs will be lost. Additionally, if the Merger is not completed, depending upon the reasons for not completing the Merger, including whether we have received or entered into a competing takeover proposal, we may be required to pay Duke Energy a termination fee of $400 million. The costs associated with not completing the Merger could have a material effect on our financial results.

If completed, our merger with Duke Energy may not achieve the anticipated results and benefits.

We and Duke Energy entered into the Merger Agreement with the expectation that the Merger would result in various benefits, including, among other things, cost savings and operating efficiencies primarily relating to the regulated businesses. Achieving the anticipated benefits of the Merger is subject to a number of uncertainties, including whether our businesses and the businesses of Duke Energy can be integrated in an efficient, effective and timely manner. As noted above, as a result of obtaining all necessary regulatory approvals, certain restrictions or conditions may be imposed on the combined company that materially impact or limit the benefits anticipated by us as a result of the Merger. The combined company is also subject to the risk that the expected cost savings and operational synergies may not be fully realized. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected liquidity provided by the combined company and diversion of management's time and energy and could have an adverse effect on the combined company's business, financial results and prospects.

We will be subject to business uncertainties and contractual restrictions while the merger with Duke Energy is pending that could adversely affect our financial results.

Uncertainty about the effect of the Merger on employees or suppliers may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties may impair our ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter, and could cause suppliers and others that deal with us to seek to change existing business relationships.

Employee retention and recruitment may be particularly challenging prior to the completion of the Merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite our retention and recruiting efforts, key employees depart or fail to accept employment with us because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, our business operations and financial results could be adversely affected.

Merger- and integration-related issues will place a significant burden on management and internal resources. The diversion of management time on merger-related issues could affect our financial results.

In addition, the Merger Agreement restricts us, without Duke Energy's consent, from making certain acquisitions and taking other specified actions, including limiting our total capital spending, limiting the extent to which we can obtain financing through long-term debt and equity issuances or increasing the Parent's common stock dividend rate until the Merger occurs or the Merger Agreement terminates. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to consummation of the Merger or termination of the Merger Agreement. Unless the Merger Agreement is terminated earlier, we and Duke Energy will each have the right to terminate the Merger Agreement if the Merger has not been completed by July 8, 2012.

The scope of necessary repairs of the delamination of CR3 could prove more extensive than is currently identified, such repairs could prove not to be feasible, the costs of repair and/or replacement power could exceed our estimates and insurance coverage or may not be recoverable through the regulatory process; the occurrence of any of which could adversely affect our financial condition, results of operations and cash flows.

In September 2009, CR3 began an outage for normal refueling and maintenance as well as an uprate project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination (or separation) within the concrete at the periphery of the containment building, which resulted in an extension of the outage. After analysis, PEF determined that the concrete delamination at CR3 was caused by redistribution of stresses in the containment wall that occurred when PEF created an opening to accommodate the replacement of the unit's steam generators. In March 2011, the work to return the plant to service was suspended after monitoring equipment at the repair site identified a new delamination that occurred in a different section of the outer wall after the repair work was completed and during the late stages of retensioning the containment building. Subsequent to March 2011, monitoring equipment has detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations could occur during the repair process. CR3 has remained out of service while PEF conducted an engineering analysis and review of the new delamination and evaluated repair options.

In June 2011, PEF notified the NRC and the FPSC that it plans to repair the CR3 containment structure and estimates it will return CR3 to service in 2014. The repair option selected entails systematically removing and replacing concrete in substantial portions of the containment structure walls. The planned option does not include replacing concrete in the area where concrete was replaced during the initial repair. PEF's preliminary cost estimate for this repair, as filed with the FPSC on June 27, 2011, is between $900 million and $1.3 billion, although a number of factors will affect the repair schedule, return-to-service date and costs of repair, including regulatory reviews, final engineering designs, contract negotiations, ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis and other developments. In addition to regulatory reviews, our assessment and plans for recovery of costs and repair of CR3 are being reviewed by Duke Energy. PEF believes the actions taken and costs incurred in response to the CR3 delamination have been prudent and, accordingly, believes that replacement power and repair costs not recoverable through insurance to be recoverable through PEF's fuel cost-recovery clause or base rates.

While the foregoing reflects PEF's current intentions and estimates with respect to CR3, the costs, timing and feasibility of additional repairs to CR3, the cost of replacement power, and the degree of recoverability of these costs, are all subject to significant uncertainties. Additional developments with respect to the condition of the CR3 structures, costs that are greater than anticipated, recoverability that is less than anticipated and/or the inability to return CR3 to service all could adversely affect our financial condition, results of operations and cash flows. See Note 8C for additional information related to the CR3 outage.

We are subject to fluid and complex government regulations that may have a negative impact on our business, financial condition, results of operations and cash flows.

We are subject to comprehensive regulation by multiple federal, state and local regulatory agencies, which significantly influences our operating environment and may affect our ability to recover costs from utility customers. We are required to comply with numerous laws and regulations and to obtain numerous permits, approvals and certificates from the governmental agencies that regulate various aspects of our business, including customer rates, retail service territories, reliability of our transmission system, applicable renewable energy and energy-efficiency standards, environmental compliance, issuances of securities, asset acquisitions and sales, accounting policies and practices, and the operation of generating facilities. 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. Changes in laws and regulations as well as changes in federal administrative policy are ongoing and the ultimate costs of compliance cannot be precisely estimated. Such changes could have an adverse impact on our financial condition, results of operations and cash flows, particularly if the costs of those changes are not fully recoverable from our ratepayers.

The rates that PEC and PEF may charge retail customers for electric power are subject to the authority of state regulators. Accordingly, our profit margins and ability to earn an adequate return on investment could be adversely affected if we do not control and prudently manage costs to the satisfaction of regulators, or if we do not obtain successful outcomes in our regulatory proceedings. Such regulatory decisions may be impacted by economic and public policy considerations within the respective jurisdictions.

The NCUC, the SCPSC and the FPSC each exercise regulatory authority for review and approval of the retail electric power rates charged within its respective state. The Utilities' state utility commissions approve base rates, which by law must give a utility a reasonable opportunity to recover its operating costs and return on invested capital. They also approve recovery through cost-recovery clauses of certain additional costs, known as "pass-through" costs, which vary by jurisdiction; examples include fuel costs, certain purchased power costs, qualified nuclear costs and specified environmental costs. The commissions can disagree with our request of appropriate base rates, and can disallow either requested base rates or pass-through recoveries on the grounds that such costs were not reasonable and prudent.

Regulatory decisions may also impact prospective revenues and earnings, affect the timing of the recognition of revenues and expenses and may overturn past decisions used in determining our revenues and expenses. Management continually evaluates the anticipated recovery of regulatory assets, liabilities and revenues subject to refund and provides allowances as deemed necessary. In the event that our assessment of the probability of recovery through the ratemaking process is incorrect, we will adjust the associated regulatory asset or liability to reflect the change in our assessment or any regulatory disallowances. A change in our evaluation of the probability of recovery of regulatory assets or a regulatory disallowance of all or a portion of our costs could adversely impact our financial condition, results of operations and cash flows.

The Utilities expect increased future expenditures in several key areas including, but not limited to, environmental compliance, new and existing generation, transmission and distribution facilities, renewable energy and energy-efficiency standards compliance (as applicable), DSM programs and fuel and other commodities. Such cost increases will be subject to scrutiny from regulators, policymakers and ratepayers. As referenced above, the commissions may disallow any costs that they find unreasonable and imprudent.

Our financial performance depends on the successful operation of electric generating facilities by the Utilities and their ability to deliver electricity to customers.

Operating our electric generating facilities and delivery systems involves many risks, including:

- operator error and breakdown or failure of equipment or processes, including repair and replacement power costs;
- failure of information technology systems and network infrastructure;
- operational limitations imposed by environmental or other regulatory requirements;
- limitations imposed on our nuclear generating units by regulatory agencies or a failure to obtain required licenses for our nuclear generating units, as discussed later;
- inadequate or unreliable access to transmission and distribution assets;
- labor disputes and inability to recruit and retain skilled technical workers;
- inability to successfully and timely execute repair, maintenance and/or refueling outages;
- interruptions to the supply of fuel and other commodities used in generation;
- failure to comply with FERC-mandated reliability standards for the bulk power electric system;
- inadequate coal combustion product management (disposal or beneficial use) capabilities;
- failure to adequately forecast system requirements and commodity requirements; and
- catastrophic events such as hurricanes, floods, extreme drought, earthquakes, fires, explosions, terrorist attacks, pandemic health events or other similar occurrences.

Occurrences of these events could adversely affect our financial condition, results of operations and cash flows.

A significant portion of our generating facilities was constructed many years ago. Aging equipment, even if maintained in accordance with industry practices, may require significant capital expenditures. Failure of equipment or facilities could potentially increase O&M expense, purchased power expense and capital expenditures.

A cyber attack could adversely affect our business, financial condition, results of operations and cash flows.

Information security risks have generally increased in recent years as a result of the proliferation of new technologies and the increased sophistication and activities of cyber attacks. Through our smart grid and other initiatives, we have increasingly connected equipment and systems related to the generation, transmission and distribution of electricity to the Internet. Because of the critical nature of our infrastructure and the increased accessibility enabled through connection to the Internet, we may face a heightened risk of cyber attack. In the event of such an attack, we could have our business operations disrupted, property damaged and customer information stolen; experience substantial loss of revenues, response costs and other financial loss; and be subject to increased regulation, litigation and damage to our reputation.

Meeting the anticipated demand in our service territories and fulfilling our environmental compliance strategies will require, among other things, modernization of coal-fired generating facilities, the construction of new generating facilities and the siting and construction of associated transmission facilities. We may not be able to obtain required licenses, permits and rights of way; successfully and timely complete construction; or recover the cost of such new generation and transmission facilities through our base rates or other recovery mechanisms, any of which could adversely impact our financial condition, results of operations and cash flows.

Meeting the anticipated demand within the Utilities' service territories and complying with existing and potential environmental laws and regulations will require a balanced approach. The three main elements of this balanced solution are: (1) expanding our energy-efficiency programs; (2) investing in the development of alternative energy resources for the future; and (3) operating state-of-the-art power systems that produce energy cleanly and efficiently by modernizing existing plants and pursuing options for building new plants and associated transmission facilities.

The risks of each of the elements of our balanced solution include, but are not limited to, the following:

Energy-Efficiency and New Energy Resources

We are expanding our DSM, energy-efficiency and conservation programs and will continue to pursue additional initiatives as these programs can be effective ways to reduce energy costs, offset the need for new power plants and protect the environment.

We are subject to the risk that our customers may not participate in our conservation programs or that the results from these programs may be less than anticipated. This could impact our compliance with state-mandated energy-efficiency standards as discussed in the risks regarding renewable energy standards. Also, not achieving the energy-efficiency and conservation measurements we assumed in our long-term resource planning could require us to further expand our generation capacity or purchase additional power at prevailing market rates.

We are also subject to the risk that customer participation in these programs or new technologies that impact the quantity and pattern of electricity usage may decrease our electric sales and require us to seek future rate increases to cover our prudently incurred costs.

As discussed further in the risk factor related to renewable energy standards, we are actively engaged in a variety of alternative energy projects. These alternative energy projects may be determined not to be cost-efficient or cost-effective.

Modernization and Construction of Generating Plants

We are currently evaluating our options for new generating plants, including gas and nuclear technologies. We are implementing our announced plan to retire certain coal-fired units in North Carolina that do not have emission control equipment by the end of 2013 and to construct new natural gas-fueled units at certain of these facilities. We are also evaluating the possibility of converting certain of these facilities to be fueled by natural gas or biomass. At this time, no definitive decision has been made regarding the construction of nuclear plants.

Decisions to build new power plants and successful completion of such construction projects are based on many factors including:

- projected system load growth;
- performance of existing generation fleet;
- availability of competitively priced alternative energy sources;
- projections of fuel prices, availability and security;
- the regulatory environment, including the ability to recover costs and earn an appropriate return on investment;
- operational performance of new technologies;

- the time required to permit and construct;
- environmental impact;
- both public and policymaker support, including support for siting of power plant and associated transmission;
- siting and construction of transmission facilities;
- cost and availability of construction equipment, materials and skilled labor;
- nuclear decommissioning costs, insurance and costs of security;
- ability to obtain financing on favorable terms; and
- availability of adequate water supply.

There is no assurance that we will be able to successfully and timely construct new generating facilities or to expand or modernize existing facilities within our projected budgets or that those expenditures will be recoverable through our base rates or other recovery mechanisms. As with any major construction undertaking, completion could be delayed or prevented, or cost overruns could be incurred, as a result of numerous factors, including shortages of material and labor, labor disputes, weather interferences, difficulties in obtaining necessary licenses or permits or complying with license or permit conditions, and unforeseen engineering, environmental or geological problems. These construction projects are long-term and may involve facility designs that have not been previously constructed or that have not been finalized when that project is commenced. Consequently, the projects could be subject to significant cost increases for labor, materials, scope changes and changes in design. Unsuccessful construction, expansion or modernization efforts could be subject to additional costs and/or the write-off of our investment in the project or improvement.

The construction of new power plants and associated expansion of our transmission system will require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support the construction. Additionally, borrowings incurred to finance construction may adversely impact our leverage, which could increase our cost of capital. For certain new baseload generating facilities, we may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks, but we cannot be certain we will be able to successfully negotiate any such arrangement. Furthermore, joint ventures or joint ownership arrangements also present risks and uncertainties, including those associated with sharing control over the construction and operation of a facility and reliance on the other party's financial or operational strength.

Our assumptions regarding future growth and resulting power demand in our service territories may not be realized. Like other parts of the United States, our service territories and business have been negatively impacted by the current economic conditions. The timing and extent of the recovery of the economy cannot be predicted. We may increase our baseload capacity based on anticipated growth levels and have excess capacity if those levels are not realized. The resulting excess capacity may exceed the reserve margins established by the NCUC, SCPSC and FPSC to meet our obligation to serve retail customers and, as a result, may not be recoverable.

Nuclear

In addition to the risks discussed above, the successful construction of a new nuclear power plant requires the satisfaction of a number of conditions. The conditions include, but are not limited to, the continued operation of the industry's existing nuclear fleet in a safe, reliable and cost-effective manner, an efficient and successful licensing process and a viable program for managing spent nuclear fuel. We cannot provide certainty that these conditions will exist. While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. We will continue to evaluate the ongoing viability of our nuclear construction projects based on certain criteria, including obtaining the COL; public, regulatory and political support; adequate financial cost-recovery mechanisms; and availability and terms of capital financing. Adverse changes in these criteria could result in project cost increases or project termination.

PEF has entered into an EPC agreement for Levy. However, because of schedule shifts, we executed an amendment to the EPC agreement and will postpone major construction activities on the project until after the NRC issues the COL. Because we have executed an amendment to the EPC agreement and anticipate negotiating additional amendments upon receipt of the COL, we cannot currently predict the timing of when those obligations will be satisfied or the magnitude of any change. PEF has completed suspension negotiations with the equipment vendors regarding those long lead time equipment items for which work was suspended.

In addition, other COL applicants could be pursuing regulatory approval, permitting and construction at roughly the same time as we would. Consequently, there may be shortages of qualified individuals to design, construct and operate these proposed new nuclear facilities.

Gas

In addition to the risks discussed above, the successful construction of a gas-fired plant requires access to an adequate supply of natural gas. The gas pipeline infrastructure in eastern and western North Carolina is limited. Existing pipelines will have to be extended to the new plant locations prior to commencement of operations, which introduces the risks associated with a critical construction project not under our direct control. Power plants fueled by fossil fuels such as natural gas and fuel oil emit GHGs, which may be subject to future regulation.

Coal

In addition to the risks discussed above, the successful modernization of a coal-fired power plant requires the satisfaction of a number of conditions, including, but not limited to, consideration of emissions that impact air and water quality and management of coal combustion products such as slag, bottom ash and fly ash.

We are subject to renewable energy standards that may have a negative impact on our business, financial condition, results of operations and cash flows.

We are subject to state renewable energy standards in North Carolina. North Carolina's standards include use of energy from specified renewable energy resources or implementation of energy-efficiency measures totaling 3 percent by 2012 and increasing to 12.5 percent by 2021. Florida energy law enacted in 2008 includes provisions for development of a renewable portfolio standard but the rulemaking process is not complete. We may be subject to additional state or federal level standards in the future that could require the Utilities to produce or buy a higher portion of their energy from renewable energy sources. Mandated state and federal standards could result in the use of renewable energy sources that are not cost-effective in order to comply with requirements. If we are not able to receive retail rates reflecting our costs or investments to comply with the state or federal standards, our financial condition, results of operations and cash flows may be adversely affected.

There are inherent potential risks in the operation of nuclear facilities, including environmental, health, safety, regulatory, terrorism, and financial risks, that could result in fines or the shutdown of our nuclear units, which may present potential financial exposures in excess of our insurance coverage.

PEC operates four nuclear units (three of which are jointly owned) and PEF has one jointly owned nuclear unit. In addition, we are exploring the possibility of expanding our nuclear generating capacity to meet future expected baseload generation needs. Our nuclear facilities are subject to operational, environmental, health and financial risks such as the ability to dispose of spent nuclear fuel, maintaining adequate capital reserves for decommissioning, limitations on amounts and types of insurance available, potential operational liabilities and extended outages, 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, damages from an accident or business interruption at our nuclear units could exceed the amount of our insurance coverage. For PEF, it may incur liabilities to co-owners in the event of extended outages or operation at less than full capacity. If the Utilities are not allowed to recover the additional costs incurred either through insurance or regulatory mechanisms, our results of operations could be negatively impacted.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generating facilities. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit, or take some combination of these actions, 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 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 financial condition, results of operations and cash flows. 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.

Our nuclear facilities have operating licenses that need to be renewed periodically. We anticipate successful renewal of these licenses. However, potential terrorist threats and increased public scrutiny of utilities could result in an extended process with higher licensing or compliance costs.

With construction beginning on a number of new nuclear facilities around the world, and the prospect of several projects across the United States, there will be increased competition within the energy sector for skilled technical workers for both the construction and operation of nuclear facilities. Our ability to successfully operate our nuclear facilities is dependent upon our continued ability to recruit and retain skilled technical workers.

We are subject to numerous environmental laws and regulations that require significant capital expenditures, increase our cost of operations, and 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 production, handling and disposal. These laws and regulations can result in increased capital, operating and other costs, particularly with regard to enforcement efforts focused on existing power plants and compliance plans with regard to new and existing power plants. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, authorizations and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. Failure to comply with applicable regulations and permits might result in the imposition of fines and penalties by regulatory authorities. We cannot provide assurance that existing environmental regulations will not be revised or that new environmental regulations will not be adopted or become applicable to us. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a material adverse effect on our results of operations, particularly if those costs are not fully recoverable from our ratepayers.

In addition, we may be deemed a responsible party for environmental clean-up at sites identified by a regulatory body or private party. We cannot predict with certainty the amount or timing of 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. While we accrue for probable costs that can be reasonably estimated, not all costs can be reasonably estimated or accrued and actual costs may materially exceed our accruals. Material costs in excess of our accruals could have an adverse impact on our financial condition, results of operations and cash flows.

Our coal-fired plants produce coal combustion products, primarily ash. The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion residues. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or additional environmental controls for groundwater protection, and future mitigation of related impacts could have a material impact on our financial condition, results of operations and cash flows. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures.

Our compliance with evolving environmental regulations, including those regarding water quality and the reduction of emissions of NOx, SO_2 and mercury from coal-fired power plants, is anticipated to require significant capital expenditures that could impact our financial condition. These costs are anticipated to be eligible for regulatory recovery through either base rates or cost-recovery clauses.

The operation of emission control equipment needed to comply with requirements set by various environmental regulations increases our operating costs and reduces the generating capacity of our coal-fired plants. O&M expenses significantly increase due to the additional personnel, materials and general maintenance associated with operation of the equipment. Operation of the emission control equipment requires the procurement of significant quantities of reagents, such as limestone and ammonia. Future increases in demand for these items from other utility companies operating similar equipment could increase our costs associated with operating the equipment. Additionally, the operation of emission control equipment may result in the development of collateral issues that require further remedial actions, resulting in additional expenditures and operating costs.

We are subject to risks associated with climate change, which could have a negative impact on our business, financial condition, results of operations and cash flows. Future legislation or regulations related to climate change may impose significant restrictions on CO_2 and other GHG emissions. We may incur significant costs to comply with such legislation or regulations or in connection with related litigation. Physical risks associated with climate change could impact us.

Growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other GHGs. Any future legislative or regulatory actions taken to address global climate change represent a business risk to our operations and the full impact of such initiatives on our operations cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time, for which the Utilities would seek corresponding rate recovery. Reductions in CO_2 emissions to the levels specified by some proposals could be materially adverse to our financial condition, results of operations and cash flows if associated costs of control or limitation cannot be recovered from ratepayers.

Potential climate change impacts in the southeastern United States could include warmer days and nights, increased total rainfall from heavy storms, increased severe weather events, sea level rise and increased drought conditions. An increase in the number of heat waves, periods of drought and sea level rise could result in changes in energy demand due to shifting populations and industry. As noted below, severe weather may adversely affect our results of operations.

We could become subject to litigation related to the purported impacts of GHG emissions. A number of legal actions have been filed against us and other electric utilities asserting public and private nuisance, trespass and negligence claims.

Because weather conditions directly influence the demand for, our ability to provide and the cost of providing electricity, our financial condition, results of operations and cash flows can fluctuate on a seasonal or quarterly basis and can be negatively affected by changes in weather conditions and severe weather.

Weather conditions in our service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to our customers. As a result, our future overall operating results may fluctuate substantially on a seasonal basis. In addition, we have historically sold less power, and consequently earned less income, when weather conditions were mild. Unusually mild weather could diminish our results of operations and cash flows and harm our financial condition.

Sustained severe drought conditions could impact generation by PEC's hydroelectric plants, as well as our fossil and nuclear plant operations, as these facilities use water for cooling purposes and for the operation of environmental compliance equipment. Furthermore, destruction caused by severe weather events, such as hurricanes, tornadoes, severe thunderstorms, snow and ice storms, can result in lost operating revenues due to outages; property damage, including downed transmission and distribution lines; and additional and unexpected expenses to mitigate storm damage.

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 condition, results of operations and cash flows.

We are subject to incurring significant costs resulting from damage sustained during severe weather events. While the Utilities have historically been granted regulatory approval to defer and amortize or collect from customers the majority of significant storm costs incurred, the Utilities' storm cost-recovery petitions may not always be granted or may not be granted in a timely manner. If we cannot recover costs associated with future severe weather events in a timely manner, or in an amount sufficient to cover our actual costs, our financial condition, results of operations and cash flows could be materially and adversely impacted.

Under its 2010 settlement agreement, PEF is allowed to recover the costs of named storms on an expedited basis through a surcharge on monthly residential customer bills for storm costs. In the event the storm costs exceed the maximum allowed surcharge, which will be eliminated under the 2012 settlement agreement, excess additional costs can be deferred and recovered in a subsequent year or years as determined by the FPSC. Additionally, the order approving the settlement agreement allows PEF to use the surcharge to replenish the storm damage reserve to a specified level after storm costs are fully recovered.

PEC does not maintain a storm damage reserve account and does not have a cost-recovery clause to recover storm costs. PEC may request recovery of significant storm-related costs; PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over agreed-upon time periods.

Our revenues, operating results and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions. We are also impacted by the demand and competitive state of the wholesale market.

Our revenues, operating results and financial condition are impacted by customer growth and usage. Customer growth can be impacted by population growth as well as by economic factors, including, but not limited to, job growth and housing market trends. The Utilities are impacted by the economic cycles of the customers we serve. As our service territories experience economic downturns, residential customer consumption patterns may change and our revenues may be negatively impacted. If our commercial and industrial customers experience economic downturns, their consumption of electricity may decline and our revenues can be negatively impacted. Like other parts of the United States, our service territories and business have been impacted by the current economic conditions. The timing and extent of the recovery of the economy cannot be predicted. Additionally, our customers could voluntarily reduce their consumption of electricity in response to decreases in their disposable income or individual energy conservation efforts.

Wholesale revenues fluctuate with regional demand, fuel prices and contracted capacity. Our wholesale profitability is dependent upon market conditions and our ability to renew or replace expiring wholesale contracts on favorable terms. Based on economic conditions in effect when wholesale contracts expire, the Utilities may not be successful in renewing or replacing expiring contracts.

Fluctuations in commodity prices or availability may adversely affect various aspects of the Utilities' operations as well as the Utilities' financial condition, results of operations and cash flows.

We are exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, nuclear fuel, electricity and other energy-related commodities, including emission allowances, as a result of our ownership of energy-related assets. Fuel costs are recovered primarily through cost-recovery clauses, subject to the Utilities' state utility commissions' approval. Additionally, we have hedging strategies in place to mitigate fluctuations in commodity supply prices, but to the extent that we do not cover our entire exposure to commodity price fluctuations, or our hedging procedures do not work as planned, there can be no assurances that our financial performance will not be negatively impacted by price fluctuations. Additionally, we are exposed to risk that our counterparties will not be able to perform their obligations. Should our counterparties fail to perform, we might be forced to replace the underlying commitment at prevailing market prices. In such an event, we might incur losses in addition to the amounts, if any, already paid to the counterparties.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Downgrades in our credit ratings could lead to additional collateral posting requirements. We continually monitor our derivative positions in relation to market price activity.

Volatility in market prices for fuel and power may result from, among other items:

- weather conditions;
- seasonality;
- power usage;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- technological changes;
- availability of competitively priced alternative energy sources;
- demand for energy commodities;
- production levels of natural gas, crude oil and refined products, nuclear fuel and coal;
- natural disasters, wars, terrorism, embargoes and other catastrophic events; and
- federal, state and foreign energy and environmental regulation and legislation.

In addition, we anticipate significant capital expenditures for environmental compliance and baseload generation. The completion of these projects within established budgets is contingent upon many variables including the securing of labor and materials at estimated costs. The demand and prices for labor and materials are subject to volatility and may increase in the future. We are subject to the risk that cost overages may not be recoverable from ratepayers and our financial condition, results of operations and cash flows may be adversely impacted.

Prices for emission allowance credits fluctuate. While allowances are eligible for annual recovery in PEF's jurisdictions in Florida and PEC's in South Carolina, no such annual recovery exists in North Carolina for PEC. Future changes in the price of allowances could have a significant adverse financial impact on us and PEC and, consequently, on our results of operations and cash flows.

As a holding company with no revenue-generating operations, the Parent is dependent on upstream cash flows from its subsidiaries, primarily the Utilities; its commercial paper program; its credit facility; and its ability to access the long-term debt and equity capital markets.

The Parent is a holding company and, as such, has no revenue-generating operations of its own. The primary cash needs at the Parent level are our common stock dividend, interest and principal payments on the Parent's senior unsecured debt and potentially funding a portion of the Utilities' capital expenditures through equity contributions. The Parent's ability to meet these needs is typically funded with dividends from the Utilities generated from their earnings and cash flows, and to a lesser extent, dividends from other subsidiaries; repayment of funds due to the Parent by its subsidiaries; the Parent's credit facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets.

Prior to funding the Parent, its subsidiaries have financial obligations that must be satisfied, including, among others, their respective debt service, preferred dividends and obligations to trade creditors. Additionally, the Utilities could retain their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from the Parent. Should the Utilities not be able to pay dividends or repay funds due to the Parent or if the Parent cannot access the commercial paper market, its credit facility or the long-term debt and equity capital markets, the Parent's ability to pay principal, interest and dividends would be restricted. The Parent could change its existing common stock dividend policy based upon these and other business factors.

Our business is dependent on our ability to successfully access capital markets on favorable terms. Limits on our access to capital may adversely impact our ability to execute our business plan or pursue improvements that we would otherwise rely on for future growth.

Our cash requirements are driven by the capital-intensive nature of our Utilities. In addition to operating cash flows, we rely heavily on commercial paper, long-term debt and equity issuances. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy will be adversely affected. Market disruptions or a downgrade of our credit ratings could increase our cost of borrowing and may adversely affect our ability to access the financial markets. If we cannot fund our expected capital expenditures and debt maturities through normal operations or by accessing capital markets, our business plans, financial condition, results of operations and cash flows may be adversely impacted.

We typically issue commercial paper to meet short-term liquidity needs. When financial and economic conditions result in tightened short-term credit markets, coupled with corresponding volatility in commercial paper durations and interest rates, we evaluate other options for meeting our short-term liquidity needs, which may include borrowing from our credit facilities, issuing short-term notes, issuing long-term debt and/or issuing equity. In addition, if our short-term credit ratings are downgraded below Tier 2 (A-2/P-2/F2) we could experience increased volatility in commercial paper durations and interest rates and our access to the commercial paper markets may be negatively impacted. In that case, we would evaluate other options for meeting our short-term liquidity needs as previously described. These alternative sources of liquidity may not be available or may not have comparable favorable terms and, thus, may impact adversely our business plans, financial condition, results of operations and cash flows.

Increases in our leverage or reductions in our cash flow 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.

As discussed above, we typically rely heavily on our commercial paper and long-term debt. Our credit agreements contain certain provisions and impose various limitations that could impact our liquidity, such as cross-default provisions and defined maximum total debt to total capital (leverage) ratios. Under these revolving credit facilities, indebtedness includes certain letters of credit, surety bonds and guarantees that are not recorded on the Consolidated Balance Sheets.

As previously discussed, we are anticipating extensive capital needs for new generation, transmission and distribution facilities, and environmental compliance expenditures. Funding these capital needs could increase our leverage and present numerous risks including those addressed below.

In the event our leverage increases such that we approach the permitted ratios, our access to capital and additional liquidity could decrease. A limitation in our liquidity could have a material adverse impact on our business strategy and our ongoing financing needs. Additionally, a significant increase in our leverage or reductions in cash flow 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;
- increasing our vulnerability to adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to debt repayment, thereby reducing funds available 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;
- requiring the issuance of additional equity;
- placing us at a competitive disadvantage compared to competitors who have less debt; and
- causing a downgrade in our credit ratings.

Any reduction in our credit ratings below investment grade would likely increase our financing costs, limit our access to additional capital and require posting of collateral, all of which could materially affect our business, financial condition, results of operations and cash flows.

While the long-term target credit ratings for the Parent and the Utilities are above the minimum investment grade rating, we cannot provide certainty that any of our current ratings 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. Such circumstances could include, among others, increases in leverage, adverse changes in other financial metrics and adverse regulatory outcomes. Our 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. Any downgrade could increase our borrowing costs, may adversely affect our access to capital and could result in the posting of additional collateral for derivatives in a liability position, which could negatively impact our financial condition, results of operations and cash flows. Any reduction in our credit ratings below investment grade could also result in collateral posting requirements for certain of our natural gas transportation contracts. 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 agency's rating should be evaluated independently of any other agency's rating.

Market performance and other changes may decrease the value of NDT funds and benefit plan assets, which then could require significant additional funding.

The performance of the capital markets affects the values of the assets held in trust to satisfy future obligations to decommission the Utilities' nuclear plants and under our defined benefit pension and other postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. Although a number of factors impact our funding requirements, a decline in the market value of the assets may increase the funding requirements of the obligations for decommissioning the Utilities' nuclear plants and under our defined benefit pension and other postretirement benefit plans. Additionally, changes in interest rates affect the liabilities under these benefit plans; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, the funding requirements of the obligations related to these benefit plans may increase due to changes in governmental regulations and participant demographics, including increased numbers of retirements or changes in life expectancy assumptions. If we are unable to successfully manage the NDT funds and benefit plan assets, our financial condition, results of operations and cash flows could be negatively affected.

Impairment of goodwill could have a significant negative impact on our financial condition, results of operations and cash flows.

Goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility reporting units, and goodwill impairment tests are performed at the utility reporting unit level.

We calculate the fair value of our utility reporting units by considering various factors, including valuation studies based primarily on income and market approaches. The calculations in both approaches are highly dependent on subjective factors such as management's estimate of future cash flows, the selection of appropriate discount and growth rates from a marketplace participant's perspective, and the selection of peer utilities and marketplace transactions for comparative valuation purposes. The estimated future cash flows are based on the Utilities' business plans that assume the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of returns on equity, the timing of anticipated significant future capital investments, the anticipated earnings and returns related to such capital investments, continued recovery of cost of service and renewal of certain contracts. These underlying assumptions and estimates are made as of a point in time. If these assumptions change or should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, the fair value of the utility reporting units could be significantly different in future periods, which could result in a future impairment charge to goodwill. Impairment of our recorded goodwill could result in volatility in our earnings under accounting principles generally accepted in the United States of America (GAAP) and an increase in our leverage, which could trigger a downgrade of our credit ratings leading to higher borrowing costs and/or dilution through additional issuances of common stock. A full impairment of all of our goodwill would cause us to violate financial or restrictive covenants contained in our indebtedness or other contractual arrangements.

Our ability to fully utilize tax credits may be limited. This risk is not applicable to PEC and PEF.

In accordance with the provisions of Internal Revenue Code Section 29/45K, we have generated tax credits based on the content and quantity of coal-based solid synthetic fuels produced and sold to unrelated parties. This tax credit program expired at the end of 2007. The timing of the utilization of the tax credits is dependent upon our taxable income, which can be impacted by a number of factors. The timing of the utilization can also be impacted by certain substantial changes in ownership, including the Merger. Additionally, in the normal course of business, our tax returns are audited by the IRS. If our tax credits were disallowed in whole or in part as a result of an IRS audit, there could be significant additional tax liabilities and associated interest for previously recognized tax credits, which could have a material adverse impact on our earnings and cash flows. Although we are unaware of any currently proposed legislation or new IRS regulations or interpretations impacting previously recorded synthetic fuels tax credits, the value of credits generated could be unfavorably impacted by such legislation or IRS regulations and interpretations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

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

ELECTRIC – PEC

PEC's 18 generating plants represent a flexible mix of fossil steam, nuclear, combustion turbine, combined cycle and hydroelectric resources, with a total summer generating capacity of 12,958 MW. Of this total, Power Agency owns approximately 700 MW. On December 31, 2011, PEC had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEC Ownership (in %)	Summer Net Capability[a] (in MW)
FOSSIL STEAM						
Asheville	Arden, N.C.	2	1964-1971	Coal	100	376
Cape Fear[b]	Moncure, N.C.	2	1956-1958	Coal	100	316
Lee[b]	Goldsboro, N.C.	3	1951-1962	Coal	100	382
Mayo	Roxboro, N.C.	1	1983	Coal	83.83	727[c]
Robinson	Hartsville, S.C.	1	1960	Coal	100	177
Roxboro	Semora, N.C.	4	1966-1980	Coal	96.3[d]	2,417[c]
Sutton[b]	Wilmington, N.C.	3	1954-1972	Coal	100	575
	Total	16				4,970
NUCLEAR						
Brunswick	Southport, N.C.	2	1975-1977	Uranium	81.67	1,870[c]
Harris	New Hill, N.C.	1	1987	Uranium	83.83	900[c]
Robinson	Hartsville, S.C.	1	1971	Uranium	100	724
	Total	4				3,494
COMBUSTION TURBINE						
Asheville	Arden, N.C.	2	1999-2000	Gas/Oil	100	324
Blewett	Lilesville, N.C.	4	1971	Oil	100	52
Cape Fear	Moncure, N.C.	2	1969	Oil	100	46
Darlington	Hartsville, S.C.	13	1974-1997	Gas/Oil	100	790
Lee	Goldsboro, N.C.	4	1968-1971	Oil	100	75
Morehead City	Morehead City, N.C.	1	1968	Oil	100	12
Smith[e]	Hamlet, N.C.	5	2001-2002	Gas/Oil	100	820
Robinson	Hartsville, S.C.	1	1968	Gas/Oil	100	11
Sutton	Wilmington, N.C.	3	1968-1969	Gas/Oil	100	61
Wayne County	Goldsboro, N.C.	5	2000-2009	Gas/Oil	100	863
Weatherspoon	Lumberton, N.C.	4	1970-1971	Gas/Oil	100	131
	Total	44				3,185
COMBINED CYCLE						
Smith[e]	Hamlet, N.C.	2	2002-2011	Gas/Oil	100	1,084
	Total	2				1,084
HYDRO						
Blewett	Lilesville, N.C.	6	1912	Water	100	22
Marshall	Marshall, N.C.	2	1910	Water	100	4
Tillery	Mount Gilead, N.C.	4	1928-1960	Water	100	87
Walters	Waterville, N.C.	3	1930	Water	100	112
	Total	15				225
TOTAL		81				12,958

(a) Summer ratings reflect compliance with NERC reliability standards and are gross of joint ownership interest.
(b) PEC has announced that it intends to retire these units no later than the end of 2013. See Item I, "Business - PEC - Fuel and Purchased Power - Oil and Gas" regarding PEC's plans to build new generation fueled by natural gas.
(c) Facilities are jointly owned by PEC and Power Agency. The capacities shown include Power Agency's share.
(d) PEC and Power Agency are joint owners of Unit 4 at the Roxboro Plant. PEC's ownership interest in this 698-MW unit is 87.06 percent.
(e) Formerly referred to as "Richmond."

At December 31, 2011, including both the total generating capacity of 12,958 MW and the total firm contracts for purchased power of 1,394 MW, PEC had total capacity resources of approximately 14,352 MW.

Power Agency has undivided ownership interests of 18.33 percent in Brunswick Unit Nos. 1 and 2, 12.94 percent in Roxboro Unit No. 4, 3.77 percent in Roxboro Common facilities, and 16.17 percent in Harris and Mayo Unit No. 1. Otherwise, PEC has good and marketable title to its principal plants and 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, 2011, PEC had approximately 6,000 circuit miles of transmission lines including 300 miles of 500-kilovolt (kV) lines and 3,100 miles of 230-kV lines. PEC also had approximately 45,000 circuit miles of overhead distribution conductor and 22,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 70 million kilovolt-ampere (kVA) in approximately 900 transformers. Distribution line transformers numbered approximately 538,000 with an aggregate capacity of approximately 24 million kVA.

ELECTRIC – PEF

PEF's 14 generating plants represent a flexible mix of fossil steam, combustion turbine, combined cycle and nuclear resources, with a total summer generating capacity of 10,019 MW. Of this total, joint owners own approximately 120 MW. On December 31, 2011, PEF had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEF Ownership (in %)	Summer Net Capability[a] (in MW)
FOSSIL STEAM						
Anclote	Holiday, Fla.	2	1974-1978	Gas/Oil	100	1,011
Crystal River	Crystal River, Fla.	4	1966-1984	Coal	100	2,295
Suwannee River	Live Oak, Fla.	3	1953-1956	Gas/Oil	100	129
	Total	9				3,435
COMBINED CYCLE						
Bartow	St. Petersburg, Fla.	1	2009	Gas/Oil	100	1,133
Hines	Bartow, Fla.	4	1999-2007	Gas/Oil	100	1,912
Tiger Bay	Fort Meade, Fla.	1	1997	Gas	100	205
	Total	6				3,250
COMBUSTION TURBINE						
Avon Park	Avon Park, Fla.	2	1968	Gas/Oil	100	48
Bartow	St. Petersburg, Fla.	4	1972	Gas/Oil	100	177
Bayboro	St. Petersburg, Fla.	4	1973	Oil	100	174
DeBary	DeBary, Fla.	10	1975-1992	Gas/Oil	100	638
Higgins	Oldsmar, Fla.	4	1969-1971	Gas/Oil	100	105
Intercession City	Intercession City, Fla.	14	1974-2000	Gas/Oil	[b]	982[c]
Rio Pinar	Rio Pinar, Fla.	1	1970	Oil	100	12
Suwannee River	Live Oak, Fla.	3	1980	Gas/Oil	100	155
Turner	Enterprise, Fla.	4	1970-1974	Oil	100	137
University of Florida Cogeneration	Gainesville, Fla.	1	1994	Gas	100	46
	Total	47				2,474
NUCLEAR						
Crystal River	Crystal River, Fla.	1	1977	Uranium	91.78	860[c] [d]
	Total	1				860
TOTAL		63				10,019

[a] Summer ratings reflect compliance with NERC reliability standards and are gross of joint ownership interest.

[b] PEF and Georgia Power Company are joint owners of a 143-MW advanced combustion turbine located at PEF's Intercession City site. Georgia Power Company has the exclusive right to the output of this unit during the months of June through September. PEF has the right for the remainder of the year.

[c] Facilities are jointly owned. The capacities shown include joint owners' share.

[d] Due to the extended outage at the CR3 nuclear generating unit that began in September 2009, no nuclear power was generated in 2011 and 2010 (See Note 8C).

At December 31, 2011, including both the total generating capacity of 10,019 MW and the total firm contracts for purchased power of 2,105 MW, PEF had total capacity resources of approximately 12,124 MW.

Several entities have acquired undivided ownership interests in CR3 in the aggregate amount of 8.22 percent. The joint ownership participants are: City of Alachua – 0.08 percent, City of Bushnell – 0.04 percent, City of Gainesville – 1.41 percent, Kissimmee Utility Authority – 0.68 percent, City of Leesburg – 0.82 percent, Utilities Commission of the City of New Smyrna Beach – 0.56 percent, City of Ocala – 1.33 percent, Orlando Utilities Commission – 1.60 percent and Seminole Electric Cooperative, Inc. – 1.70 percent. PEF and Georgia Power Company are co-owners of a 143-MW advance combustion turbine located at PEF's Intercession City Unit P11. Georgia Power Company 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 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, 2011, PEF had approximately 5,100 circuit miles of transmission lines including 200 miles of 500-kV lines and approximately 1,600 miles of 230-kV lines. PEF also had approximately 18,000 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 65 million kVA in approximately 800 transformers. Distribution line transformers numbered approximately 390,000 with an aggregate capacity of approximately 20 million kVA.

ITEM 3. LEGAL PROCEEDINGS

Legal proceedings are included in Note 22D and are incorporated by reference herein.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable

EXECUTIVE OFFICERS OF THE REGISTRANTS AT FEBRUARY 28, 2012

Name	Age	Recent Business Experience
William D. Johnson	58	**Chairman, President and Chief Executive Officer, Progress Energy and Florida Progress,** October 2007 to present; **Chairman, PEC and PEF,** from November 2007 to present; President and Chief Operating Officer, Progress Energy, from January 2005 to October 2007; Group President, PEC, from January 2004 to October 2007; Executive Vice President, PEF, from November 2000 to November 2007; Executive Vice President, Florida Progress, from November 2000 to December 2003; and Corporate Secretary, PEC, PEF, Progress Energy Service Company, LLC and Florida Progress, from November 2000 to December 2003. Mr. Johnson has been with Progress Energy (formerly CP&L) since 1992 and served as Group President, Energy Delivery, Progress Energy, from January 2004 to December 2004. Prior to that, he was President, CEO and Corporate Secretary, Progress Energy Service Company, LLC, from 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, Mr. Johnson was a partner with the Raleigh, N.C., law office of Hunton & Williams LLP where he specialized in the representation of utilities. He previously served as a law clerk to the Honorable J. Dickson Phillips Jr. of the U.S. Court of Appeals for the Fourth Circuit.
Jeffrey A. Corbett	52	**Senior Vice President, Energy Delivery, PEC,** January 2008 to present. Mr. Corbett oversees operations and services in the Carolinas, including engineering, distribution, construction, metering, power restoration, community relations and customer service. He previously served as Senior Vice President, Energy Delivery, PEF, from June 2006 to January 2008, with the same responsibilities in Florida as mentioned above. Mr. Corbett served as Vice President – Distribution for PEC, from January 2005 to June 2006. He also served PEC as Vice President – Eastern Region, from September 2002 to January 2005. Mr. Corbett joined Progress Energy in 1999 and has served in a number of roles, including General Manager of the Eastern Region and Director of Distribution Power Quality and Reliability. Before joining Progress Energy, Mr. Corbett spent 17 years with Virginia Power, serving in a variety of engineering and leadership roles.

*Vincent M. Dolan	57	**President and Chief Executive Officer, PEF,** July 2009 to present. Mr. Dolan oversees all aspects of PEF's delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Vice President – External Relations, PEF, from December 2006 to July 2009; Vice President – Regulatory & Customer Relations, PEF, from March 2005 to December 2006; and Vice President – Corporate Relations & Administrative Services, PEF, from April 2002 to March 2005. Mr. Dolan has been with PEF since 1986 in positions of increasing responsibility in the areas of operations, strategic development, customer services, and regulatory affairs. Before joining PEF, Mr. Dolan was with Foster Wheeler Energy Corporation, an international engineering and manufacturing firm.
*Michael A. Lewis	49	**Senior Vice President, Energy Delivery, PEF,** January 2008 to present. Mr. Lewis oversees operations and services in Florida, including engineering, distribution, construction, metering, power restoration, community relations, energy-efficiency, and alternative energy strategies. He previously served as Vice President, Distribution, PEF, from August 2007 to January 2008; Vice President, Distribution Engineering & Operations, PEF, from December 2005 to August 2007; Vice President, Distribution Operations & Support, PEF, from April 2004 to December 2005; and Vice President, Coastal Region, PEF, from December 2000 to April 2004. Mr. Lewis has been with PEF in a number of engineering and management positions since 1986, including District Manager, Distribution Operations Manager in Pasco County, General Manager for the South Coastal region and Regional Vice President of both the North and South Coastal regions.
Jeffrey J. Lyash	50	**Executive Vice President, Energy Supply, Progress Energy,** June 2010 to present. In this role, Mr. Lyash oversees Progress Energy's diverse fleet of generating resources, including nuclear, coal, oil, natural gas and hydroelectric stations. In addition, he oversees fuel procurement for the generating fleet and power trading operations. He also serves as Executive Vice President, PEC, since August 2009, and PEF, since July 2009. Mr. Lyash previously served as Executive Vice President, Corporate Development, Progress Energy, from July 2009 to June 2010; President and Chief Executive Officer, PEF, from June 2006 to July 2009; Senior Vice President, PEF, from November 2003 to June 2006; and Vice President Transmission in Energy Delivery, PEC, from January 2002 to October 2003. Mr. Lyash joined Progress Energy (formerly CP&L) in 1993 and spent his first eight years at the Brunswick Nuclear Plant in Southport, N.C., in a number of management roles. His last position at Brunswick was as Director of Site Operations. Before joining Progress Energy, Mr. Lyash worked for the NRC between 1984 and 1993 in a number of senior technical and management positions.

John R. McArthur	56	**Executive Vice President, Progress Energy,** September 2008 to present. In this role, Mr. McArthur is responsible for corporate and utility support functions, including Audit Services, Corporate Communications, Corporate Services, External Relations, Human Resources and Legal. He also serves as General Counsel, since April 2010, and previously from 2004 until 2009, and Corporate Secretary, since 2004, of Progress Energy. Mr. McArthur is also Executive Vice President of PEC since September 2008, Executive Vice President of PEF since November 2008 and Executive Vice President of Florida Progress Corporation since January 2010. Mr. McArthur has been with Progress Energy in a number of roles since 2001, including Senior Vice President, Corporate Relations and Vice President, Public Affairs. Before joining Progress Energy, Mr. McArthur was a senior adviser to N.C. Governor Mike Easley, handling major policy initiatives as well as media and legal affairs. Previously, he handled state government affairs for General Electric Co. Mr. McArthur also served as chief counsel in the N.C. Attorney General's office, where he supervised utility, consumer, health care, and environmental protection issues. Prior to that he was a partner with the Raleigh, N.C., law office of Hunton & Williams LLP and served as a law clerk to the Honorable Sam J. Ervin III of the U.S. Court of Appeals for the Fourth Circuit.
Mark F. Mulhern	52	**Senior Vice President and Chief Financial Officer, Progress Energy, PEC and PEF,** September 2008 to present. He previously served as Senior Vice President, Finance, PEC and PEF, from November 2007 to September 2008, and Senior Vice President, Finance, Progress Energy, from July 2007 to September 2008. Mr. Mulhern also served as President of Progress Ventures (the unregulated subsidiary of Progress Energy), from 2005 to 2008; Senior Vice President of Competitive Commercial Operations of Progress Ventures, from 2003 to 2005; Vice President, Strategic Planning of Progress Energy, from 2000 to 2003; Vice President and Treasurer of Progress Energy, from 1997 to 2000; and Vice President and Controller of Progress Energy, from 1996 to 1997. Before joining Progress Energy (formerly CP&L) in 1996, Mr. Mulhern was the Chief Financial Officer at Hydra Co Enterprises, the independent power subsidiary of Niagara Mohawk. He also spent eight years at Price Waterhouse, serving a wide variety of manufacturing and service businesses.
James Scarola	55	**Senior Vice President and Chief Nuclear Officer, PEC and PEF**, January 2008 to present. Mr. Scarola oversees all aspects of our nuclear program. He previously served as Vice President at the Brunswick Nuclear Plant from October 2005 to December 2007. Mr. Scarola joined Progress Energy (formerly CP&L) in 1998, where he served as Vice President at the Harris Nuclear Power Plant until October 2005. Mr. Scarola entered the nuclear power field in 1978 as a design engineer and has held positions in construction, start-up testing, maintenance, engineering and operations. Prior to joining Progress Energy, he was the General Manager of Florida Power & Light Company's St. Lucie Nuclear Plant.

Paula J. Sims	50	**Senior Vice President, Corporate Development and Improvement, Progress Energy,** June 2010 to present. Ms. Sims is responsible for implementing Progress Energy's balanced solution strategy for meeting the future energy needs of its customers. In addition, she oversees program development and construction of new generation projects, renewable energy and efficiency programs, supply chain, information technology and wholesale power operations. Ms. Sims is the executive sponsor for Continuous Business Excellence, Progress Energy's framework for improving processes, efficiency and overall cost management and has responsibility for environmental, health and safety. She also serves as Senior Vice President, PEC and PEF, since April 2006. Ms. Sims previously served as Senior Vice President, Power Operations, PEC and PEF, from July 2007 to June 2010; Senior Vice President, Regulated Services of PEC, from January 2006 to July 2007; Vice President, Fossil Fuel Generation of Progress Energy and PEF, from January 2006 to April 2006; Vice President, Regulated Fuels of Progress Energy, from December 2004 to December 2005; Chief Operating Officer of Progress Fuels Corporation, from February 2002 to December 2004; and Vice President, Business Operations & Strategic Planning of Progress Fuels Corporation, from June 2001 to February 2002. Before joining Progress Energy in 1999, Ms. Sims was with GE Aircraft Engines, where she served in a number of engineering, operations and plant management roles for over 15 years.
Jeffrey M. Stone	50	**Chief Accounting Officer and Controller, Progress Energy and Florida Progress,** June 2005 to present; Chief Accounting Officer, PEC and PEF, from June 2005 and November 2005, respectively, to present; and Vice President and Controller, Progress Energy Service Company, LLC, from January 2005 and June 2005, respectively to present. Mr. Stone previously served as Controller of PEF and PEC, from June 2005 to November 2005. Since 1999, Mr. Stone has served Progress Energy in a number of roles in corporate support including Vice President – Capital Planning and Control; and Executive Director – Financial Planning & Regulatory Services, as well as in various management positions with Energy Supply and Audit Services. Prior to joining Progress Energy, Mr. Stone worked as an auditor with Deloitte & Touche in Charlotte, N.C.
Lloyd M. Yates	51	**President and Chief Executive Officer, PEC,** July 2007 to present. Mr. Yates oversees all aspects of PEC's delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Senior Vice President, PEC, from January 2005 to July 2007, where he was responsible for overseeing the four operational and customer service regions in the Carolinas, as well as the distribution function. Mr. Yates served PEC as Vice President – Transmission, from November 2003 to December 2004 and as Vice President – Fossil Generation, from November 1998 to November 2003. Before joining Progress Energy (formerly CP&L) in 1998, Mr. Yates was with PECO Energy for over 16 years in several line operations and management positions.

* Indicates individual is an executive officer of Progress Energy, Inc., but not PEC.

PART II

ITEM 5. MARKET FOR REGISTRANT'S 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 under the symbol PGN. The high and low intra-day stock prices for each quarter for the past two years, and the cash dividends declared per share, are as follows:

	High	Low	Dividends Declared
2011			
First Quarter	**$ 46.83**	**$ 42.55**	**$ 0.620**
Second Quarter	**49.03**	**45.20**	**0.620**
Third Quarter	**52.42**	**42.05**	**0.620**
Fourth Quarter	**56.33**	**49.37**	**0.259**
2010			
First Quarter	$ 41.35	$ 37.04	$ 0.620
Second Quarter	40.69	37.13	0.620
Third Quarter	44.82	38.96	0.620
Fourth Quarter	45.61	43.08	0.620

The December 31 closing price of our Common Stock was $56.02 for 2011 and $43.48 for 2010. At February 23, 2012, we had 48,755 holders of record of Common Stock.

Progress Energy expects to continue its policy of paying regular cash dividends; however, dividends are subject to declaration by the board of directors, and the existing common stock dividend policy could change based upon business factors, including future earnings, capital requirements and financial condition. Additionally, the Merger Agreement restricts our ability, without Duke Energy's consent, to increase the common stock dividend rate until consummation or termination of the Merger Agreement. See MD&A "Introduction – Merger." In the fourth quarter of 2011, the board of directors declared a partial dividend of $0.259 per share in order to align our dividend payment schedule with that of Duke Energy such that following the closing of the Merger, all stockholders of the combined company would receive dividends under the Duke Energy dividend schedule. It is anticipated that the board will maintain this alignment in anticipation of the closing of the Merger during 2012. On January 20, 2012, the Progress Energy board of directors declared a full quarterly dividend of $0.620 per share payable on March 16, 2012, to shareholders of record on February 17, 2012.

Neither Progress Energy's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. Our subsidiaries have provisions restricting dividends on their securities in certain limited circumstances (See Notes 10 and 12B).

Information regarding securities authorized for issuance under our equity compensation plans is included in Progress Energy's definitive proxy statement for its 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A.

RESTRICTED STOCK UNIT AWARD PAYOUTS

(a) Securities Delivered. On October 17, 2011, December 8, 2011, and December 12, 2011, 1,108 shares, 3,500 shares and 916 shares, respectively, of our common stock were delivered to certain former employees pursuant to the terms of the Progress Energy 2007 Equity Incentive Plans (the EIP) which has been approved by Progress Energy's shareholders. The shares of common stock delivered pursuant to the EIP were newly issued shares of Progress Energy.

(b) Underwriters and Other Purchasers. No underwriters were used in connection with the delivery of our common stock described above.

(c) Consideration. The restricted stock unit awards were granted to provide an incentive to the former employees to exert their utmost efforts on Progress Energy's behalf and thus enhance our performance while aligning the employees' interest with those of our shareholders.

(d) Exemption from Registration Claimed. The common shares described in this Item were delivered pursuant to a broad-based involuntary, noncontributory employee benefit plan, and thus did not involve an offer to sell or sale of securities within the meaning of Section 2(3) of the Securities Act of 1933. Receipt of the shares of our common stock required no investment decision on the part of the recipient.

ISSUER PURCHASES OF EQUITY SECURITIES FOR FOURTH QUARTER OF 2011

Period	(a) Total Number of Shares (or Units) Purchased (1) to (5)	(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	409,839	$ 49.9474	N/A	N/A
November 1 – November 30	478,809	52.3253	N/A	N/A
December 1 – December 31	84,927	54.1318	N/A	N/A
Total	973,575	$ 51.4819	N/A	N/A

(1) At December 31, 2011, Progress Energy does not have any publicly announced plans or programs to purchase shares of its common stock.
(2) The plan administrator purchased 554,000 shares of our common stock in open-market transactions to meet share delivery obligations under the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)).
(3) The plan administrator purchased 215,565 shares of our common stock in open-market transactions to meet share delivery obligations under the Savings Plan for Employees of Florida Progress Corporation.
(4) The plan administrator purchased 202,186 shares of our common stock in open-market transactions to meet share delivery obligations under the Progress Energy Investor Plus Plan (IPP).
(5) Progress Energy withheld 1,824 shares of our common stock during the fourth quarter of 2011 to pay taxes due upon the payout of certain Restricted Stock Unit awards pursuant to the terms of the EIP.

PEC

Since 2000, the Parent has owned all of PEC's common stock, and as a result, there is no established public trading market for the stock. PEC has neither issued nor repurchased any equity securities since becoming a wholly owned subsidiary of the Parent. During 2011, 2010 and 2009, PEC paid dividends to the Parent totaling the amounts shown in PEC's Consolidated Statements of Changes in Total Equity included in the financial statements in PART II, Item 8. PEC has provisions restricting dividends in certain circumstances (See Notes 10 and 12). PEC does not have any equity compensation plans under which its equity securities are issued.

PEF

All shares of PEF's common stock are owned by Florida Progress and, as a result, there is no established public trading market for the stock. PEF has neither issued nor repurchased any equity securities since becoming an indirect subsidiary of the Parent. During 2011 and 2010, PEF paid dividends to Florida Progress totaling the amounts shown in PEF's Statements of Changes in Common Stock Equity included in the financial statements in PART II, Item 8. During 2009, PEF paid no dividends to Florida Progress. PEF has provisions restricting dividends in certain circumstances (See Notes 10 and 12). PEF does not have any equity compensation plans under which its equity securities are issued.

ITEM 6. SELECTED FINANCIAL DATA

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

PROGRESS ENERGY

	Years Ended December 31				
(in millions, except per share data)	**2011**	2010	2009	2008	2007
OPERATING RESULTS					
Operating revenues	**$ 8,907**	$ 10,190	$ 9,885	$ 9,167	$ 9,153
Income from continuing operations	**587**	867	840	778	702
Net income	**582**	863	761	836	496
Net income attributable to controlling interests	**575**	856	757	830	504
PER SHARE DATA					
Basic and diluted earnings					
Income from continuing operations attributable to controlling interests, net of tax	**$ 1.96**	$ 2.96	$ 2.99	$ 2.95	$ 2.70
Net income attributable to controlling interests	**1.94**	2.95	2.71	3.17	1.96
TOTAL ASSETS	**$ 35,059**	$ 33,054	$ 31,236	$ 29,873	$ 26,338
CAPITALIZATION AND DEBT					
Common stock equity	**$ 10,021**	$ 10,023	$ 9,449	$ 8,687	$ 8,395
Noncontrolling interests	**4**	4	6	6	84
Preferred stock of subsidiaries	**93**	93	93	93	93
Long-term debt, net[a]	**11,991**	12,137	12,051	10,659	8,737
Current portion of long-term debt	**950**	505	406	-	877
Short-term debt	**671**	-	140	1,050	201
Capital lease obligations	**211**	221	231	239	247
Total capitalization and debt	**$ 23,941**	$ 22,983	$ 22,376	$ 20,734	$ 18,634
Dividends declared per common share	**$ 2.119**[b]	$ 2.480	$ 2.480	$ 2.465	$ 2.445

[a] Includes long-term debt to affiliated trust of $273 million at December 31, 2011 and 2010, $272 million at December 31, 2009 and 2008 and $271 million at December 31, 2007 (See Note 23).

[b] In the fourth quarter of 2011, the board of directors declared a partial dividend of $0.259 per share in order to align our dividend payment schedule with that of Duke Energy, such that following the closing of the Merger, all stockholders of the combined company would receive dividends under the Duke Energy schedule.

PEC

(in millions)	2011	2010	2009	2008	2007
	Years Ended December 31				
OPERATING RESULTS					
Operating revenues	**$ 4,528**	$ 4,922	$ 4,627	$ 4,429	$ 4,385
Net income	**516**	602	514	534	501
Net income attributable to controlling interests	**516**	603	516	534	501
Net income attributable to parent	**513**	600	513	531	498
TOTAL ASSETS	**$ 16,102**	$ 14,899	$ 13,502	$ 13,165	$ 11,955
CAPITALIZATION AND DEBT					
Common stock equity	**$ 5,088**	$ 5,180	$ 4,657	$ 4,301	$ 3,752
Noncontrolling interests	**-**	-	3	4	4
Preferred stock	**59**	59	59	59	59
Long-term debt, net	**3,693**	3,693	3,703	3,509	3,183
Current portion of long-term debt	**500**	-	6	-	300
Short-term debt[(a)]	**219**	-	-	110	154
Capital lease obligations	**12**	14	15	16	17
Total capitalization and debt	**$ 9,571**	$ 8,946	$ 8,443	$ 7,999	$ 7,469

(a) Includes notes payable to affiliated companies related to the money pool program of $31 million at December 31, 2011, and $154 million at December 31, 2007.

PEF

The information called for by Item 6 is omitted for PEF pursuant to Instruction I(2)(a) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

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

The following combined MD&A is separately filed by Progress Energy, PEC and PEF. Information contained herein relating to PEC and PEF individually is filed by such company on its own behalf. Neither of the Utilities makes any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself.

The following MD&A 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 "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors," for a discussion of the factors that may impact any such forward-looking statements made herein.

MD&A includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures, "Ongoing Earnings" and "Base Revenues," discussed below. Generally, a non-GAAP financial measure is a numerical measure of financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. The non-GAAP financial measures should be viewed as a supplement to, and not a substitute for, financial measures presented in accordance with GAAP. Non-GAAP measures as presented herein may not be comparable to similarly titled measures used by other companies.

MD&A should be read in conjunction with the accompanying financial statements found elsewhere in this report.

PROGRESS ENERGY

INTRODUCTION

Our reportable business segments are PEC and PEF, and their primary operations are the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. The Corporate and Other segment primarily includes the operations of the Parent, PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative requirements as a separate reportable business segment.

MERGER

On January 8, 2011, Duke Energy and Progress Energy entered into the Merger Agreement. Pursuant to the Merger Agreement, Progress Energy will be acquired by Duke Energy in a stock-for-stock transaction and become a wholly owned subsidiary of Duke Energy. Consummation of the Merger is subject to customary conditions, including, among others things, approval of the shareholders of each company, expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and receipt of approvals, to the extent required, from the FERC, the Federal Communications Commission, the NRC, the NCUC, the Kentucky Public Service Commission and the SCPSC. Although there are no merger-specific regulatory approvals required in Indiana, Ohio or Florida, the companies will continue to update the public service commissions in those states on the Merger, as applicable and as required.

See Item 1A, “Risk Factors,” and Note 2 for risks and additional information related to the Merger.

The Merger Agreement includes certain restrictions, limitations and prohibitions as to actions we may or may not take in the period prior to consummation of the Merger as discussed below. At this time, we do not anticipate modifying our 2012 strategy discussed below but cannot predict the impact consummation of the Merger will have on our long-term strategy. The combined company’s expected balance sheet and credit metrics are anticipated to enhance our growth opportunities and strategic options.

We do not expect the Merger to have a significant impact on our cash requirements and sources of liquidity during 2012. Pursuant to the Merger Agreement, only limited equity issuances through certain employee benefit plans and stock option plans are permitted. In the event the Merger does not close by the Merger Agreement termination date of July 8, 2012, we may also use equity offerings or ongoing sales of common stock through the IPP and/or employee benefit and stock option plans to support our liquidity requirements. Additionally, the Merger Agreement restricts our ability, without Duke Energy’s consent, to increase the common stock dividend rate until consummation or termination of the Merger Agreement. Total capital spending and the extent to which we can obtain financing through long-term debt issuances are also limited.

After consummation of the Merger, Progress Energy intends to cease filing periodic reports with the SEC as soon as practicable. PEC and PEF intend to continue to file periodic reports with the SEC.

Certain substantial changes in ownership of Progress Energy, including the Merger, can impact the timing of the utilization of tax credit carry forwards and net operating loss carry forwards (See Note 15).

The companies are targeting for the Merger to close during 2012. Until the Merger has received all necessary approvals and has closed, the companies will continue to operate as separate entities. Accordingly, the information presented in this Form 10-K is presented solely for the Progress Registrants on a pre-merger basis.

STRATEGY

Progress Energy is an integrated energy company with two electric utility subsidiaries that operate in regulated retail utility markets in North Carolina, South Carolina and Florida and have access to competitive wholesale markets in the eastern United States. The Utilities have 23,000 MW of regulated generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities.

We are committed to pursuing the successful completion of the Merger with Duke Energy. We believe that the Merger will provide substantial strategic and financial benefits to shareholders, customers and most employees. These benefits include increased financial strength and flexibility, joint dispatch fuel savings for customers in the Carolinas and a larger, more diverse and better-positioned regulated utility business. We are working to address remaining regulatory conditions while preserving the value of the Merger for all of our stakeholders.

We are focused on excelling in the fundamentals of our business including safety, operational excellence and customer service; consistently achieving our financial objectives; maintaining constructive relations with regulators, political leaders and the general public; as well as focusing on strong leadership that fully engages our workforce for high performance. In addition to these fundamentals, we are concentrating on the following four focus areas:

- Achieve effective integration planning and merger approvals
- Improve the performance of our nuclear fleet
- Optimize our balanced solution strategy
- Accelerate Continuous Business Excellence

EFFECTIVE INTEGRATION PLANNING AND MERGER APPROVALS

As more fully discussed in "Merger" we are pursuing the remaining required regulatory approvals for the Merger and have completed the majority of our merger integration processes. Our integration plans take advantage of the strengths of both companies and the best practices in the industry. Maintaining constructive relations with regulators, public leaders and the general public is fundamental to our business, which will be critical for obtaining the remaining merger approvals. Until the Merger closes, Progress Energy and Duke Energy will continue to operate as two entirely separate companies.

IMPROVE NUCLEAR FLEET PERFORMANCE

We continue to implement a comprehensive, multi-year improvement plan designed to strengthen and align the performance of PEC's nuclear fleet. We are committed to raising our nuclear fleet performance to a consistently high level of safety, reliability and value. To do that, we have made a number of organizational changes and have intensified our focus on plant operations, outage planning and execution, and continuous improvement. We are also leveraging the expertise and capabilities of our company as a whole to meet these nuclear fleet objectives. We have taken significant remediation steps to improve performance of PEC's nuclear fleet after a number of unplanned outages in 2010, and the early signs of progress are evident in the results of 2011 operating statistics. The PEC nuclear fleet set a new generation record in 2011 with a capacity factor of 95.2 percent in 2011 compared to 2010's 83.5 percent. The initial implementation of the multi-year improvement plan for Robinson was a particular focus in 2011 and resulted in higher O&M expense, as discussed in "Results of Operations." We anticipate a lesser impact on O&M in subsequent years as we continue implementation of the improvement plan.

We are continuing in our process to resolve the extended outage of CR3. We have taken appropriate actions to maintain the unit's containment in a safe condition throughout the course of the outage. Through the first quarter of 2012, we expect to continue analyzing and refining information related to the engineering, cost and schedule for the repair of CR3. We are continuing to work with our insurers and federal and state regulators. Additional developments with respect to the condition of the CR3 structures, costs that are greater than anticipated, recoverability that is less than anticipated, and/or the inability to return CR3 to service could all adversely affect our financial results and liquidity. As discussed in "Matters Impacting Future Results and Liquidity," the FPSC has approved a comprehensive settlement agreement between PEF and consumer advocates in Florida that addresses recovery of CR3 replacement power and repair costs.

BALANCED SOLUTION STRATEGY

Our three-pronged balanced solution strategy seeks to meet future customer needs and evolving public policy in a way that creates long-term value for our customers and shareholders. Through a combination of investments and initiatives in energy efficiency, alternative and renewable energy and a state-of-the-art power system, we are addressing the challenge facing our industry of meeting demand and new environmental regulations while controlling costs. Expenditures to achieve our balanced solution are anticipated to be recoverable under base rates or cost-recovery mechanisms implemented in our state jurisdictions.

First, our DSM, EE and energy-conservation programs provide customers with incentives for efficiency improvements and include customer education and outreach efforts. In addition, we are a leader in the utility industry in promoting and preparing for plug-in electric vehicles. We operate a research fleet of plug-in vehicles; maintain partnerships with plug-in vehicle automakers including General Motors, Nissan and Ford; and are participating in a number of demonstration and research programs involving plug-in vehicles and the associated charging stations, including solar-powered charging stations.

Second, we are actively engaged in a variety of alternative energy projects. We have executed contracts to purchase approximately 380 MW of electricity generated from solar, biomass and municipal solid waste sources. The majority of these projects should be online within the next five years. While this currently represents a small percentage of our total capacity, we will continue to pursue additional contracts for these and other alternative energy sources. PEC is on track to meet the first of the targets set under North Carolina's renewable energy portfolio standard, 3 percent of retail electric sales in 2012.

Third, we are pursuing numerous options for a state-of-the-art power system. Our objective is to have a diverse, flexible generation portfolio that enables us to provide reliable, affordable power with a smaller environmental footprint. Fleet modernization and a substantial smart grid program will help us meet this objective. We are also keeping our options open to build advanced nuclear plants.

We have made significant progress in the coal-to-gas fleet transition we announced in 2009. Our initial plans were to retire 11 North Carolina coal units that do not have scrubbers by no later than the end of 2017. These smaller, aging units represent approximately 30 percent (or 1,500 MW) of our North Carolina fleet. In 2011, we accelerated the final closure timetable to 2013 and retired the first of the units. To replace the coal-fired generation to be retired, we placed a 600-MW combined-cycle plant in service in mid-2011 and have broken ground on two other plants, which are projected to begin service in 2013. Of our approximately 7,500 MW of coal-fired generation, we have scrubbed and installed emission control equipment on almost 5,000 MW in the Carolinas and Florida at an investment of over $2 billion. As a result of the installation of environmental controls and the retirement of unscrubbed coal-fired plants, our emissions profile will be significantly reduced while strengthening our fuel diversification. We believe that these actions will help address growing environmental constraints on coal-fired generation and take advantage of favorable prices for U.S. natural gas as well as improvements in combined-cycle technology.

We are making a significant investment in smart grid technology with initiatives partially funded by $200 million of federal matching infrastructure funds. Reimbursements totaling $89 million have been received to date.

New nuclear generation is a vital long-term part of our balanced solution strategy. While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building one or more plants. The Utilities have each filed a COL application with the NRC for two additional reactors each at Harris and at Levy. We have focused on Levy given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions, as well as existing state legislative policy that is supportive of nuclear projects. During 2011, the NRC approved the reactor design selected for Levy and Harris, and a decision on the Levy COL is expected in 2013. Once we have received the COL, we will assess the project and determine the schedule. As discussed in "Matters Impacting Future Results and Liquidity," PEF's comprehensive settlement agreement addresses recovery of Levy costs through 2017.

We are preparing for an energy future that includes, among other things, carbon reductions and emerging technologies such as smart grid and plug-in electric vehicles. We believe that our balanced solution strategy provides an effective, flexible framework that will prepare us for this new energy future.

CONTINUOUS BUSINESS EXCELLENCE

For the past several years, we have been applying a continuous improvement framework to our operations through our Continuous Business Excellence initiative. Through a disciplined approach to identifying and eliminating waste and continuously improving our business, we are developing sustainable process improvements. In addition, we have been applying the "Lean" process to our operations (Lean is a set of principles, tools and techniques for improving the operating performance of any business). In addition to the improvement events held across our company during 2011, we are applying Lean principles to our merger integration activities discussed above.

MATTERS IMPACTING FUTURE RESULTS AND LIQUIDITY

Our future financial results and liquidity can be impacted by a number of factors, as more fully discussed in Item 1, "Business," and Item 1A, "Risk Factors." Declines in demand for electricity can result from economic downturns as well as unseasonable weather. The Utilities are subject to regulation on the federal and state level. Changes in laws and regulation as well as changes in federal administrative policy are ongoing and the ultimate costs of compliance cannot be precisely estimated. Such changes could have an adverse impact on our financial condition, results of operations and cash flows, particularly if the costs of those changes are not fully recoverable from our ratepayers.

As more fully discussed in Note 8C, the FPSC has approved a comprehensive settlement agreement between PEF and consumer advocates in Florida that provides customers a refund of $288 million, removes CR3 from base rates while we continue to analyze options for the plant, limits the costs customers will be charged through 2017 for Levy and allows for base rates to adjust in 2013. The settlement agreement will take effect with the first billing cycle of January 2013. When all the agreement provisions are factored in, the estimated 2013 total increase for the average PEF residential bill is approximately $4.93 per 1,000 kilowatt-hours (kWh), or 4 percent, over current rates. The total PEF customer bill for 2013 and beyond will change as the cost-recovery clause components of the customer bills change. Those expenses are filed and reviewed with the FPSC each year, separate from the base rate.

Despite the recent court-ordered stay of a new air pollution regulation that was slated to go into effect in 2012, we continue to work to lessen the environmental impact of our power plants through our balanced solution strategy. We expect environmental regulations to continue to evolve, including those regarding water quality and the reduction of emissions from coal-fired plants. Compliance is anticipated to require significant capital expenditures that could impact our financial condition, results of operations and cash flows. However, we anticipate that such costs would be eligible for regulatory recovery through either base rates or cost-recovery clauses.

RESULTS OF OPERATIONS

In this section, we provide analysis and discussion of earnings and the factors affecting earnings on both a GAAP and non-GAAP basis. We introduce our results of operations in an overview section followed by a more detailed analysis and discussion by business segment.

We compute our non-GAAP financial measurement "Ongoing Earnings" as GAAP net income attributable to controlling interests less discontinued operations and the effects of certain identified gains and charges, which are considered Ongoing Earnings adjustments. Some of the excluded gains and charges have occurred in more than one reporting period but are not considered representative of fundamental core earnings. Ongoing Earnings is not a measure calculated in accordance with GAAP, and should be viewed as a supplement to, and not a substitute for, our results of operations presented in accordance with GAAP. Ongoing Earnings as presented here may not be comparable to similarly titled measures used by other companies.

A reconciliation of Ongoing Earnings to GAAP net income attributable to controlling interests follows:

(in millions except per share data)	PEC	PEF	Corporate and Other	Total	Per Share
Year ended December 31, 2011					
Ongoing Earnings	**$ 541**	**$ 530**	**$ (200)**	**$ 871**	**$ 2.95**
Impairment, net of tax[a]	**(2)**	**-**	**-**	**(2)**	**(0.01)**
Plant retirement charge, net of tax[a]	**(1)**	**-**	**-**	**(1)**	**-**
CVO mark-to-market, net of tax[a]	**-**	**-**	**(45)**	**(45)**	**(0.16)**
Merger and integration costs, net of tax[a]	**(25)**	**(21)**	**-**	**(46)**	**(0.16)**
CR3 indemnification charge, net of tax[a]	**-**	**(20)**	**-**	**(20)**	**(0.06)**
Amount to be refunded to customers, net of tax[b]	**-**	**(177)**	**-**	**(177)**	**(0.60)**
Discontinued operations attributable to controlling interests, net of tax	**-**	**-**	**(5)**	**(5)**	**(0.02)**
Net income (loss) attributable to controlling interests[c]	**$ 513**	**$ 312**	**$ (250)**	**$ 575**	**$ 1.94**
Year ended December 31, 2010					
Ongoing Earnings	$ 618	$ 462	$ (191)	$ 889	$ 3.06
Impairment, net of tax[a]	(5)	(1)	-	(6)	(0.02)
Plant retirement charge, net of tax[a]	(1)	-	-	(1)	-
Change in the tax treatment of the Medicare Part D subsidy	(12)	(10)	-	(22)	(0.08)
Discontinued operations attributable to controlling interests, net of tax	-	-	(4)	(4)	(0.01)
Net income (loss) attributable to controlling interests[c]	$ 600	$ 451	$ (195)	$ 856	$ 2.95
Year ended December 31, 2009					
Ongoing Earnings	$ 540	$ 460	$ (154)	$ 846	$ 3.03
Impairment, net of tax[a]	-	-	(2)	(2)	(0.01)
Plant retirement charge, net of tax[a]	(17)	-	-	(17)	(0.06)
CVO mark-to-market	-	-	19	19	0.07
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax[a]	(10)	-	-	(10)	(0.04)
Discontinued operations attributable to controlling interests, net of tax	-	-	(79)	(79)	(0.28)
Net income (loss) attributable to controlling interests[c]	$ 513	$ 460	$ (216)	$ 757	$ 2.71

(a) Calculated using assumed tax rate of 40 percent to the extent items are tax deductible.

(b) Calculated using PEF's statutory tax rate of 38.6 percent.

(c) Net income attributable to controlling interests is shown net of preferred stock dividend requirement of $3 million and $2 million at PEC and PEF, respectively.

Management uses the non-GAAP financial measure Ongoing Earnings (i) as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends; (ii) as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations; (iii) as a measure for determining levels of incentive compensation; and (iv) in communications with our board of directors, employees, shareholders, analysts and investors concerning our financial performance. Management believes this non-GAAP measure is appropriate for understanding the business and assessing our potential future performance, because excluded items are limited to those that management believes are not representative of our fundamental core earnings (See Note 20).

OVERVIEW

FOR 2011 AS COMPARED TO 2010 and 2010 AS COMPARED TO 2009

For the year ended December 31, 2011, our net income attributable to controlling interests was $575 million, or $1.94 per share, compared to net income attributable to controlling interests of $856 million, or $2.95 per share, for the same period in 2010. The decrease as compared to prior year was primarily due to:

- the charge recorded for the amount to be refunded to customers through the fuel clause in accordance with PEF's 2012 settlement agreement (Ongoing Earnings adjustment);
- less favorable impact of weather at the Utilities;
- loss recorded due to mark-to-market change in fair value of contingent value obligations (CVOs) (Ongoing Earnings adjustment) and
- lower wholesale base revenues at the Utilities.

Partially offsetting these items was:

- lower depreciation and amortization expense recoverable through base rates in accordance with PEF's 2010 settlement agreement.

For the year ended December 31, 2010, our net income attributable to controlling interests was $856 million, or $2.95 per share, compared to net income attributable to controlling interests of $757 million, or $2.71 per share, for the same period in 2009. The increase as compared to prior year was primarily due to:

- favorable weather at the Utilities and
- lower loss from discontinued non-utility businesses (Ongoing Earnings adjustment).

Partially offsetting these items was:

- higher O&M expenses at the Utilities.

PROGRESS ENERGY CAROLINAS

PEC contributed net income available to parent totaling $513 million, $600 million and $513 million in 2011, 2010 and 2009, respectively. The decrease in net income available to parent for 2011 as compared to 2010 was primarily due to the less favorable impact of weather and merger and integration costs. The increase in net income available to parent for 2010 as compared to 2009 was primarily due to the favorable impact of weather, favorable allowance for funds used during construction (AFUDC) equity and favorable retail customer growth and usage, partially offset by higher O&M expenses.

PEC contributed Ongoing Earnings of $541 million, $618 million and $540 million for 2011, 2010 and 2009, respectively. The 2011 Ongoing Earnings adjustments to net income available to parent were a $25 million charge, net of tax, for merger and integration costs, a $2 million impairment of certain miscellaneous investments, net of tax, and a $1 million plant retirement charge, net of tax, related to PEC's decision to retire certain coal-fired generating units prior to the end of their estimated useful lives. The 2010 Ongoing Earnings adjustments to net income available to parent were a $12 million charge for the change in the tax treatment of the Medicare Part D subsidy, a $5 million impairment of certain miscellaneous investments and other assets, net of tax, and a $1 million plant retirement charge, net of tax. The 2009 Ongoing Earnings adjustments to net income available to parent were a $17 million plant retirement charge, net of tax, and recording a $10 million charge, net of tax, for a cumulative prior period adjustment related to certain employee life insurance benefits. Management does not consider these items to be representative of PEC's fundamental core earnings and excluded these items in computing PEC's Ongoing Earnings.

REVENUES

The revenue tables that follow present the total amount and percentage change of total operating revenues and its components. "Base Revenues" is a non-GAAP measure and is defined as operating revenues excluding clause-recoverable regulatory returns, miscellaneous revenues, fuel and other pass-through revenues and refunds, if any. We and PEC consider Base Revenues a useful measure to evaluate PEC's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, applicable portions of purchased power expenses and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. PEC's clause-recoverable regulatory returns include renewable energy clause revenues and the return on asset component of DSM and EE. The reconciliation and analysis that follows is a complement to the financial information provided in accordance with GAAP.

A reconciliation of PEC's Base Revenues to GAAP operating revenues, including the percentage change by customer class and by year, follows:

(in millions) Customer Class	**2011**	% Change	2010	% Change	2009
Residential	**$ 1,185**	(4.6)	$ 1,242	10.1	$ 1,128
Commercial	**712**	(1.9)	726	2.7	707
Industrial	**365**	-	365	2.5	356
Governmental	**65**	-	65	10.2	59
Unbilled	**(34)**	NM	10	NM	5
Total retail base revenues	**2,293**	(4.8)	2,408	6.8	2,255
Wholesale base revenues	**285**	(6.6)	305	(1.0)	308
Total Base Revenues	**2,578**	(5.0)	2,713	5.9	2,563
Clause-recoverable regulatory returns	**31**	138.5	13	44.4	9
Miscellaneous	**129**	(6.5)	138	21.1	114
Fuel and other pass-through revenues	**1,790**	NM	2,058	NM	1,941
Total operating revenues	**$ 4,528**	(8.0)	$ 4,922	6.4	$ 4,627

NM - not meaningful

PEC's total Base Revenues were $2.578 billion and $2.713 billion for 2011 and 2010, respectively. The $135 million decrease in Base Revenues was due primarily to the $107 million unfavorable impact of weather and $20 million lower wholesale base revenues. The unfavorable impact of weather was driven by 20 percent lower heating-degree days and 5 percent lower cooling-degree days than 2010. Cooling-degree days were 19 percent higher than normal and heating-degree days were 9 percent lower than normal in 2011. See "Seasonality and the Impact of Weather" in Item 1, "Business," for a summary of degree days and weather estimation. The lower wholesale base revenues was primarily due to the $15 million impact of lower demand driven by the unfavorable impact of weather and the $7 million impact of a contract that expired in early 2011.

PEC's clause-recoverable regulatory returns increased $18 million in 2011 primarily due to recovery of increased spending on DSM programs.

PEC's total Base Revenues were $2.713 billion and $2.563 billion for 2010 and 2009, respectively. The $150 million increase in Base Revenues was due primarily to the $115 million favorable impact of weather and the $36 million favorable impact of retail customer growth and usage. The favorable impact of weather was driven by 15 percent higher heating-degree days and 24 percent higher cooling-degree days than 2009. Additionally, cooling degree-days were 30 percent higher and heating degree-days were 14 percent higher than normal. The favorable impact of retail customer growth and usage was driven by an increase in the average usage per retail customer and a net 10,000 increase in the average number of customers for 2010 compared to 2009.

PEC's miscellaneous revenues increased $24 million in 2010, which includes $10 million higher transmission revenues driven by higher rates resulting from transmission asset additions.

PEC's electric energy sales in kWh and the percentage change by customer class and by year were as follows:

(in millions of kWh) Customer Class	**2011**	% Change	2010	% Change	2009
Residential	**18,148**	(5.0)	19,108	11.6	17,117
Commercial	**13,844**	(2.4)	14,184	4.0	13,639
Industrial	**10,613**	(0.5)	10,665	2.9	10,368
Governmental	**1,610**	2.3	1,574	5.1	1,497
Unbilled	**(597)**	NM	172	NM	360
Total retail kWh sales	**43,618**	(4.6)	45,703	6.3	42,981
Wholesale	**12,605**	(10.0)	13,999	0.2	13,966
Total kWh sales	**56,223**	(5.8)	59,702	4.8	56,947

The decrease in retail kWh sales in 2011 was primarily due to unfavorable impact of weather, as previously discussed.

The decrease in wholesale kWh sales in 2011 was primarily due to unfavorable impact of weather, as previously discussed, and a contract that expired in early 2011.

The increase in retail kWh sales in 2010 was primarily due to favorable weather, as previously discussed.

EXPENSES

<u>*Fuel and Purchased Power*</u>

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation and energy purchased in the market to meet customer load. Fuel and a portion of 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 from or refund to customers and is recorded as deferred fuel expense, which is included in fuel used in electric generation on the Consolidated Statements of Income.

Fuel and purchased power expenses were $1.702 billion for 2011, which represents a $286 million decrease compared to 2010. This decrease was primarily due to the $169 million impact of lower fuel rates and the $112 million impact of lower system requirements resulting from the unfavorable impact of weather compared to 2010. See "Electric Utility Regulated Operating Statistics – PEC" in Item 1, "Business," for a summary of average fuel costs.

Fuel and purchased power expenses were $1.988 billion for 2010, which represents a $79 million increase compared to 2009. This increase was primarily due to the $324 million impact of higher system requirements resulting from favorable weather and the impact of nuclear plant outages on PEC's generation mix, partially offset by $151 million decreased fuel costs in 2010 driven by lower coal and gas prices and $104 million lower deferred fuel expense. The decrease in deferred fuel expense was primarily due to higher fuel and purchased power expenses and lower fuel rates in North Carolina.

Operation and Maintenance

O&M expense was $1.182 billion for 2011, which represents a $24 million increase compared to 2010. This increase was primarily due to $48 million higher nuclear plant O&M costs, $41 million of merger and integration costs, $23 million higher storm costs, $12 million higher fossil generation outage and maintenance costs, $7 million higher vegetation management expense, and a $6 million prior-year nuclear insurance refund, partially offset by $91 million lower nuclear plant outage costs, the $27 million noncapital portion of a judgment from spent fuel litigation (See Note 22D) and the $2 million prior-year impairment of other assets. The higher nuclear plant O&M costs are primarily due to increased spending to improve the performance of Robinson and higher spent fuel storage costs in 2011 as compared to 2010. The lower nuclear plant outage costs are primarily due to two nuclear refueling and maintenance outages in 2011 compared to three in 2010. There were $2 million and $1 million of coal plant retirement charges recognized in 2011 and 2010, respectively. Management does not consider merger and integration costs, impairments and charges recognized for the retirement of generating units prior to the end of their estimated useful lives to be representative of PEC's fundamental core earnings. Therefore, the impacts of these items are excluded in computing PEC's Ongoing Earnings. Certain O&M expenses such as the cost of reagents for emission control equipment and wheeling charges are recoverable through cost-recovery clauses. In aggregate, O&M expenses primarily recoverable through base rates increased $15 million compared to the same period in 2010.

O&M expense was $1.158 billion for 2010, which represents an $86 million increase compared to 2009. This increase was primarily due to $78 million higher nuclear plant outage and maintenance costs, $11 million higher employee benefits expense driven by revised actuarial estimates, $7 million higher emission expense primarily due to sales of NOx emission allowances in the prior year and the $2 million impairment of other assets, partially offset by $27 million lower coal plant retirement charges. The higher nuclear plant outage and maintenance costs are primarily due to three nuclear refueling and maintenance outages in 2010 compared to two in 2009 as well as extended outages and more emergent work in 2010 as compared to 2009. As previously discussed, management does not consider impairments and charges recognized for the retirement of generating units prior to the end of their estimated useful lives to be representative of PEC's fundamental core earnings. Therefore, the impacts of these items are excluded in computing PEC's Ongoing Earnings. Also, as previously discussed, certain O&M expenses are recoverable through cost-recovery clauses. In aggregate, O&M expenses primarily recoverable through base rates increased $69 million compared to the same period in 2009.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $514 million, $479 million and $470 million for 2011, 2010 and 2009, respectively. The $35 million increase in 2011 was primarily due to higher depreciable asset base driven by placing the newly constructed combined-cycle unit at the Smith Energy Complex into service in mid-2011.

Other

Other operating expense was $34 million for 2011, which represents a $26 million increase compared to 2010. The $34 million expense in 2011 was primarily due to the $28 million retail disallowance of replacement power costs resulting from the prior-year performance of nuclear plants (See Note 8B). The $8 million expense in 2010 was primarily due to the $7 million impairment of certain miscellaneous investments. Management does not consider impairments to be representative of PEC's fundamental core earnings. Therefore, the impacts of impairments are excluded in computing PEC's Ongoing Earnings.

Total Other Income, Net

Total other income, net was $71 million for 2011, which represents a $4 million increase compared to 2010. This increase was primarily due to favorable AFUDC equity of $7 million resulting from increased construction project costs, partially offset by $4 million impairment of certain miscellaneous investments. Management does not consider impairments to be representative of PEC's fundamental core earnings. Therefore, the impacts of impairments are excluded in computing PEC's Ongoing Earnings.

Total other income, net was $67 million for 2010, which represents a $47 million increase compared to 2009. This increase was primarily due to favorable AFUDC equity of $31 million resulting from increased construction project costs and a $16 million cumulative prior period adjustment charge recorded in 2009 related to certain employee life insurance benefits. The prior period adjustment was not material to 2009 or previously issued financial statements. Management determined that the adjustment should be excluded in computing PEC's Ongoing Earnings.

Income Tax Expense

Income tax expense was $256 million, $350 million and $277 million in 2011, 2010 and 2009, respectively. The $94 million decrease in 2011 compared to 2010 was primarily due to the $72 million impact of lower pre-tax income and the $12 million prior-year impact of the change in the tax treatment of the Medicare Part D subsidy resulting from federal health care reform enacted in 2010 (See Note 17). The $73 million income tax expense increase in 2010 compared to 2009 was primarily due to the $64 million impact of higher pre-tax income and the $12 million impact of the Medicare Part D subsidy previously discussed. Management does not consider the change in the tax treatment of the Medicare Part D subsidy to be representative of PEC's fundamental core earnings and, therefore, the amount is excluded in computing PEC's Ongoing Earnings.

PROGRESS ENERGY FLORIDA

PEF contributed net income available to parent totaling $312 million, $451 million and $460 million in 2011, 2010 and 2009, respectively. The decrease in net income available to parent for 2011 as compared to 2010 was primarily due to the charge for the amount to be refunded to customers through the fuel clause in accordance with the 2012 settlement agreement and the less favorable impact of weather, partially offset by lower depreciation and amortization expense recoverable through base rates. The decrease in net income available to parent for 2010 compared to 2009 was primarily due to unfavorable AFUDC equity and higher O&M expenses, partially offset by the favorable impact of weather and higher clause-recoverable regulatory returns.

PEF contributed Ongoing Earnings of $530 million, $462 million and $460 million in 2011, 2010 and 2009, respectively. The 2011 Ongoing Earnings adjustments to net income available to parent were a $177 million charge, net of tax, for the amount to be refunded to customers through the fuel clause, a $21 million charge, net of tax, for merger and integration costs and a $20 million charge, net of tax, for indemnification for the estimated future years' joint owner replacement power costs for CR3. The 2010 Ongoing Earnings adjustments to net income available to parent were a $10 million charge for the change in the tax treatment of the Medicare part D subsidy and a $1 million impairment of other assets, net of tax. Management does not consider these charges to be representative of PEF's fundamental core earnings and excluded these charges in computing PEF's Ongoing Earnings. There were no Ongoing Earnings adjustments in 2009.

REVENUES

The revenue tables that follow present the total amount and percentage change of total operating revenues and its components. "Base Revenues" is a non-GAAP measure and is defined as operating revenues excluding clause-recoverable regulatory returns, miscellaneous revenues, fuel and other pass-through revenues and refunds, if any. We and PEF consider Base Revenues a useful measure to evaluate PEF's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, applicable portions of purchased power and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. PEF's clause-recoverable regulatory returns include the revenues associated with the return on asset component of nuclear cost-recovery and environmental cost recovery clause (ECRC) revenues. The reconciliation and analysis that follows is a complement to the financial information we provide in accordance with GAAP.

A reconciliation of PEF's Base Revenues to GAAP operating revenues, including the percentage change by customer class and by year, follows:

(in millions) Customer Class	2011	% Change	2010	% Change	2009
Residential	**$ 983**	(5.9)	$ 1,045	10.5	$ 946
Commercial	**356**	(0.8)	359	5.6	340
Industrial	**74**	(1.3)	75	4.2	72
Governmental	**90**	(2.2)	92	5.7	87
Unbilled	**(24)**	NM	17	NM	9
Total retail base revenues	**1,479**	(6.9)	1,588	9.2	1,454
Wholesale base revenues	**110**	(31.3)	160	(22.7)	207
Total Base Revenues	**1,589**	(9.1)	1,748	5.2	1,661
Clause-recoverable regulatory returns	**182**	5.2	173	98.9	87
Miscellaneous	**209**	(3.2)	216	14.3	189
Amount to be refunded to customers	**(288)**	NM	-	-	-
Fuel and other pass-through revenues	**2,677**	NM	3,117	NM	3,314
Total operating revenues	**$ 4,369**	(16.8)	$ 5,254	0.1	$ 5,251

PEF's total Base Revenues were $1.589 billion and $1.748 billion for 2011 and 2010, respectively. The $159 million decrease in Base Revenues was due primarily to the $112 million unfavorable impact of weather and $50 million lower wholesale base revenues. The unfavorable impact of weather was driven by 61 percent lower heating-degree days than 2010. Additionally, heating-degree days were 12 percent lower than normal. See "Seasonality and the Impact of Weather" in Item 1, "Business," for a summary of degree days and weather estimation. The lower wholesale base revenues were primarily due to decreased revenues from contracts that expired in 2010.

PEF's amount to be refunded to customers of $288 million in 2011 represents the refund to customers through the fuel clause in accordance with the 2012 settlement agreement (See Note 8C). PEF will refund $129 million in each of 2013 and 2014, and an additional $10 million annually to residential and small commercial customers in 2014, 2015 and 2016. Management does not consider the amount to be refunded to customers to be representative of PEF's fundamental core earnings. Therefore, the impact of this item is excluded in computing PEF's Ongoing Earnings.

PEF's total Base Revenues were $1.748 billion and $1.661 billion for 2010 and 2009, respectively. The $87 million increase in Base Revenues was due primarily to the $88 million favorable impact of weather and the $50 million impact of increased retail base rates associated with the repowered Bartow Plant, partially offset by $47 million lower wholesale base revenues and the $5 million unfavorable impact of net retail customer growth and usage. The favorable impact of weather was driven by 89 percent higher heating-degree days than 2009. Additionally, heating-degree days were 124 percent higher than normal. The lower wholesale base revenues were primarily due to an amended contract with a major customer. The unfavorable impact of net retail customer growth and usage was driven by a decrease in the average usage per retail customer, partially offset by a net 4,000 increase in the average number of customers for 2010 compared to 2009.

PEF's clause-recoverable regulatory returns increased $86 million in 2010 primarily due to higher returns on ECRC assets due to placing approximately $1 billion of CAIR projects into service in late 2009 and mid-2010.

PEF's miscellaneous revenues increased $27 million in 2010 primarily due to $20 million higher transmission revenues driven by favorable weather and $8 million higher right-of-use revenues related to the use of easements and land.

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

(in millions of kWh) Customer Class	**2011**	% Change	2010	% Change	2009
Residential	**19,238**	(6.3)	20,524	5.8	19,399
Commercial	**11,892**	-	11,896	0.1	11,884
Industrial	**3,243**	0.7	3,219	(2.0)	3,285
Governmental	**3,224**	(1.9)	3,286	0.9	3,256
Unbilled	**(629)**	NM	458	NM	131
Total retail kWh sales	**36,968**	(6.1)	39,383	3.8	37,955
Wholesale	**2,610**	(32.3)	3,857	0.6	3,835
Total kWh sales	**39,578**	(8.5)	43,240	3.5	41,790

The decrease in retail kWh sales in 2011 was primarily due to unfavorable impact of weather, as previously discussed.

Wholesale kWh sales decreased in 2011 primarily due to decreased sales from contracts that expired in 2010.

The increase in retail kWh sales in 2010 was primarily due to the favorable impact of weather as previously discussed.

Wholesale kWh sales increased in 2010 primarily due to the favorable impact of weather, which resulted in increased deliveries under a certain capacity contract that has high demand and low energy charges. Despite the increase in sales, wholesale base revenues decreased primarily due to a contract amendment as previously discussed.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation and energy purchased in the market to meet customer load. Fuel and a portion of 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 from or refund to customers and is recorded as deferred fuel expense, which is included in fuel used in electric generation on the Consolidated Statements of Income.

Fuel and purchased power expenses totaled $2.284 billion in 2011, which represents a $307 million decrease compared to 2010. This decrease was primarily due to lower current year fuel and purchased power costs of $366 million and a decrease in the recovery of deferred capacity costs of $158 million, partially offset by an increase in deferred fuel expense of $217 million. The lower fuel and purchased power costs were driven by the $385 million impact of lower system requirements in 2011 as a result of the unfavorable impact of weather as previously discussed and lower natural gas prices in 2011, partially offset by the $32 million CR3 indemnification charge for the estimated joint owner replacement power costs for future years (through the expiration of the indemnification provisions of the joint owner agreement) that was recorded in 2011 (See Note 8C for a discussion of the CR3 outage and Note 22C for a discussion of the related indemnification). The decrease in the recovery of deferred capacity costs was due to decreased current year rates. Deferred fuel expense increased due to the higher under-recovered fuel costs in 2010 as a result of higher system requirements due to extreme weather. See "Electric Utility Regulated Statistics - PEF" in Item 1, "Business," for a summary of average fuel costs. Management does not consider the CR3 indemnification of future years' joint owner replacement power costs to be representative of PEF's fundamental core earnings. Therefore, the impact of this item is excluded in computing PEF's Ongoing Earnings.

Fuel and purchased power expenses totaled $2.591 billion in 2010, which represents a $163 million decrease compared to 2009. This decrease was primarily due to lower deferred fuel expense of $520 million resulting from lower fuel rates, which assumed the CR3 outage was completed in 2009, partially offset by increased fuel and purchased power costs in 2010 of $189 million and an increase in the recovery of deferred capacity costs of $167 million. The increased fuel and purchased power costs were primarily driven by higher system requirements resulting from the favorable impact of weather and CR3 replacement power costs net of insurance recovery. The increase in the recovery of deferred capacity costs was primarily due to increased rates and higher system requirements due to favorable weather.

Operation and Maintenance

O&M expense was $881 million in 2011, which represents a $31 million decrease compared to 2010. This decrease was primarily due to $19 million lower ECRC costs resulting from a refund of the 2010 over-recovery, $14 million lower employee-related expenses, $11 million lower vegetation management expense, $7 million lower uncollectible account expense, $5 million lower environmental remediation expense and $2 million prior-year impairment of other assets, partially offset by $35 million of merger and integration costs. Management does not consider impairments and merger and integration costs to be representative of PEF's fundamental core earnings. Therefore, the impact of these items is excluded in computing PEF's Ongoing Earnings. The ECRC costs and certain other O&M expenses are recoverable through cost-recovery clauses and, therefore, have no material impact on earnings. In aggregate, O&M expenses primarily recoverable through base rates decreased $15 million compared to the same period in 2010.

O&M expense was $912 million in 2010, which represents a $73 million increase compared to 2009. This increase was primarily due to the $34 million prior-year pension deferral in accordance with an FPSC order; $22 million higher employee benefits expense driven by revised actuarial estimates; $18 million higher Energy Conservation Cost Recovery Clause (ECCR) costs driven by higher deferred expenses due to higher rates, increased energy sales and increased customer usage of load management programs and home improvement incentives; the $11 million prior-year impact of a change in vacation benefits policy; and the $2 million impairment of other assets. These increases are partially offset by $22 million favorable ECRC costs due to lower NOx allowances used resulting from a scrubber placed in service in December 2009. The ECCR and ECRC expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. Management does not consider impairments to be representative of PEF's fundamental core earnings. Therefore, the impacts of impairments are excluded in computing PEF's Ongoing Earnings. In aggregate, O&M expenses primarily recoverable through base rates increased $80 million compared to the same period in 2009.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $169 million for 2011, which represents a $257 million decrease compared to 2010. This decrease was primarily due to the $190 million increase in the reduction of the cost of removal component of amortization expense in accordance with the 2010 settlement agreement (See Note 8C) and $45 million lower nuclear cost-recovery amortization. The decrease in the nuclear cost-recovery amortization is due to lower approved recovery of preconstruction and carrying costs resulting from schedule shifts in the Levy project (See Note 8C). The nuclear cost-recovery amortization is recovered through a cost-recovery clause and, therefore, has no material impact on earnings. In aggregate, depreciation, amortization and accretion expenses recoverable through base rates or the ECRC decreased $178 million compared to the same period in 2010. In accordance with PEF's 2010 and 2012 settlement agreements, PEF will have the discretion to reduce the cost of removal component of amortization expense in 2012 and beyond, as well, subject to limitations (See Note 8C).

Depreciation, amortization and accretion expense was $426 million for 2010, which represents a $76 million decrease compared to 2009. This decrease was primarily due to a reduction in the cost of removal component of amortization expense of $60 million in accordance with the 2010 settlement agreement, the lower depreciation rate impact of $43 million and other adjustments required in the 2010 settlement agreement of $13 million, partially offset by the $46 million impact of depreciable asset base increases. The lower depreciation rate resulted from a depreciation study in conjunction with the 2009 base rate case.

Taxes Other Than on Income

Taxes other than on income was $350 million for 2011, which represents a $12 million decrease compared to 2010. This decrease was primarily due to lower gross receipts and franchise taxes of $21 million resulting from lower operating revenues, partially offset by higher property taxes of $12 million resulting primarily from an increase in taxable plant basis. Taxes other than on income was $362 million for 2010, which represents an increase of $15 million compared to 2009, primarily due to higher property taxes of $14 million resulting primarily from placing the repowered Bartow Plant in service in mid-2009. Gross receipts and franchise taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Other

Other operating expense was income of $13 million in 2011 and expense of $4 million and $7 million in 2010 and 2009, respectively. The $13 million income in 2011 was primarily due to a favorable litigation judgment. The $7 million expense in 2009 was primarily due to regulatory disallowance of fuel costs.

Total Other Income, Net

Total other income, net was $35 million for 2011, which represents a $7 million increase compared to 2010. This increase was primarily due to $4 million favorable AFUDC equity related to higher eligible construction project costs.

Total other income, net was $28 million for 2010, which represents a $72 million decrease compared to 2009. This decrease was primarily due to $63 million unfavorable AFUDC equity related to lower eligible construction project costs, primarily due to placing the repowered Bartow Plant and CAIR projects into service in mid- and late 2009, respectively.

Total Interest Charges, Net

Total interest charges, net was $239 million for 2011, which represents a $19 million decrease compared to 2010. This decrease was primarily due to the 2011 settlement of 2004 and 2005 income tax audits.

Total interest charges, net was $258 million in 2010, which represents a $27 million increase compared to 2009. This increase was primarily due to $16 million higher interest driven by higher average long-term debt outstanding and $14 million unfavorable AFUDC debt related to costs associated with eligible construction projects as discussed above.

Income Tax Expense

Income tax expense was $180 million, $276 million and $209 million in 2011, 2010 and 2009, respectively. The $96 million decrease in 2011 compared to 2010 was primarily due to the $91 million impact of lower pre-tax income and the $10 million prior-year impact of the change in the tax treatment of the Medicare Part D subsidy resulting from federal health care reform enacted in 2010 (See Note 17). The $67 million income tax expense increase in 2010 compared to 2009 was primarily due to the $24 million impact of the unfavorable AFUDC equity discussed above, the $23 million impact of higher pre-tax income and the $10 million impact of the Medicare Part D subsidy previously discussed. AFUDC equity is excluded from the calculation of income tax expense. Management does not consider the change in the tax treatment of the Medicare Part D subsidy to be representative of PEF's fundamental core earnings. Accordingly, the impact of the change is excluded in computing PEF's Ongoing Earnings.

CORPORATE AND OTHER

The Corporate and Other segment primarily includes the operations of the Parent, PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements as a reportable business segment. A discussion of the items excluded from Corporate and Other's Ongoing Earnings is included in the detailed discussion and analysis that follows. Management believes the excluded items are not representative of our fundamental core earnings. The following table reconciles Corporate and Other's Ongoing Earnings to GAAP net income attributable to controlling interests:

(in millions)	**2011**	Change	2010	Change	2009
Other interest expense	**$ (302)**	$ (4)	$ (298)	$ (52)	$ (246)
Other income tax benefit	**117**	1	116	19	97
Other expense	**(15)**	(6)	(9)	(4)	(5)
Ongoing Earnings	**(200)**	(9)	(191)	(37)	(154)
CVO mark-to-market, net of tax	**(45)**	(45)	-	(19)	19
Impairment, net of tax	**-**	-	-	2	(2)
Discontinued operations attributable to controlling interests, net of tax	**(5)**	(1)	(4)	75	(79)
Net loss attributable to controlling interests	**$ (250)**	$ (55)	$ (195)	21	$ (216)

OTHER INTEREST EXPENSE

Other interest expense was $302 million, $298 million and $246 million for 2011, 2010 and 2009, respectively. The $52 million increase for 2010 compared to 2009 was primarily due to higher average debt outstanding at the Parent.

OTHER INCOME TAX BENEFIT

Other income tax benefit was $117 million, $116 million and $97 million for 2011, 2010 and 2009, respectively. The $19 million increase for 2010 compared to 2009 was primarily due to the favorable tax impact of higher pre-tax loss.

OTHER EXPENSE

Other expense was $15 million, $9 million and $5 million for 2011, 2010 and 2009, respectively. The $6 million increase in 2011 was primarily due to higher stock-based compensation expense resulting from the increase in Progress Energy's stock price.

ONGOING EARNINGS ADJUSTMENTS

CVO Mark-to-Market

Progress Energy issued 98.6 million CVOs in connection with the acquisition of Florida Progress in 2000. Each CVO represents the right of the holder to receive contingency payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate (See Note 16). As a result of a settlement agreement with a CVO holder and a tender offer to CVO holders at a purchase price of $0.75 per CVO (See Note 16), Progress Energy repurchased 80.1 million CVOs in 2011. Progress Energy recorded a pre-tax loss of $59 million in 2011 and a gain of $19 million in 2009 to record the change in fair value of the CVOs, which had average unit prices of $0.75 at December 31, 2011 and $0.16 at December 31, 2010 and 2009. The 18.5 million outstanding CVOs not held by Progress Energy at December 31, 2011, had a fair value of $14 million. The 98.6 million CVOs outstanding at December 31, 2010 and 2009 had a fair value of $15 million. The gain/loss recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income. Because Progress Energy is unable to predict the changes in the fair value of the CVOs, management does not consider this adjustment to be representative of our fundamental core earnings. Therefore, the impact of changes in the fair value of CVOs is excluded in computing our Ongoing Earnings.

Impairment, Net of Tax

We recorded a $3 million impairment of investments in 2009. The impairment was recorded in other, net on the Consolidated Statements of Income. Management does not consider impairments to be representative of our fundamental core earnings. Therefore, the impacts of impairments are excluded in computing our Ongoing Earnings.

Discontinued Operations Attributable to Controlling Interests, Net of Tax

We completed our business strategy of divesting of nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. See Note 4 for additional information related to discontinued operations. We recognized $5 million, $4 million and $79 million of losses from discontinued operations attributable to controlling interests, net of tax, for 2011, 2010 and 2009, respectively. Management does not consider operating results of discontinued operations to be representative of our fundamental core earnings. Therefore, the impacts of operating results of discontinued operations are excluded in computing our Ongoing Earnings.

In 2009, we recognized $79 million of expense from discontinued operations attributable to controlling interests, net of tax, which was primarily due to a jury delivering a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates previously engaged in coal-based solid synthetic fuels operations (See Note 22D). As a result, we recorded an after-tax charge of $74 million to discontinued operations, which was net of a previously recorded indemnification liability.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We prepared our Consolidated Financial Statements in accordance with GAAP. In doing so, we made certain estimates that were critical in nature to the results of operations. The following discusses those significant accounting policies and estimates that may have a material impact on our financial results and are subject to the greatest amount of subjectivity. We have discussed the development and selection of these critical accounting policies and estimates with the Audit and Corporate Performance Committee (Audit Committee) of our board of directors.

IMPACT OF UTILITY REGULATION

Our regulated utilities segments are subject to regulation that sets the rates (prices) we are permitted to charge customers based on the costs that regulatory agencies determine we are 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. The application of GAAP for regulated operations to this ratemaking process results in deferral of expense recognition and the recording of regulatory assets based on anticipated future cash inflows. As a result of the ratemaking processes in each state in which we operate, a significant amount of regulatory assets has been recorded. We continually review these regulatory 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' ratemaking processes often provide flexibility in the manner and timing of the depreciation of property, nuclear decommissioning costs and amortization of the regulatory assets.

Our conclusion that we and the Utilities meet the criteria to apply GAAP for regulated operations is a material assumption in the presentation and evaluation of our and the Utilities' financial position and results of operations. The Utilities' ability to continue to meet the criteria for application of GAAP for regulated operations could be affected in the future by actions of our regulators, competitive forces and restructuring in the electric utility industry. State regulators may not allow the Utilities to increase future retail rates required to recover their operating costs or provide an adequate return on investment, or in the manner requested. State regulators may also seek to reduce or freeze retail rates. Such events occurring over a sustained period could result in the Utilities no longer meeting the criteria for the continued application of GAAP for regulated operations. In the event that GAAP for regulated operations no longer applies to one or both of the Utilities, we are subject to the risk that regulatory assets and liabilities would be eliminated and utility plant assets may be impaired, unless an appropriate recovery mechanism was provided. Additionally, our financial condition, results of operations and cash flows may be materially impacted. See Note 8 for additional information related to the impact of utility regulation on our operations.

We evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever impairment indicators exist. If an impairment 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. Our exposure to potential impairment losses for utility plant, net is mitigated by the fact that our regulated ratemaking process generally allows for recovery of our investment in utility plant plus an allowed return on the investment, as long as the costs are prudently incurred. The carrying values of our total utility plant, net at December 31 were as follows:

(in millions)	**2011**	2010
Progress Energy	**$ 22,497**	$ 21,240
PEC	**11,887**	10,961
PEF	**10,523**	10,189

As discussed in Note 14, our financial assets and liabilities are primarily comprised of derivative financial instruments and marketable debt and equity securities held in our nuclear decommissioning trusts. Substantially all unrealized gains and losses on derivatives and all unrealized gains and losses on nuclear decommissioning trust investments are deferred as regulatory liabilities or assets consistent with ratemaking treatment. Therefore, the impact of fair value measurements from recurring financial assets and liabilities on our or the Utilities' earnings is not significant.

ASSET RETIREMENT OBLIGATIONS

Asset Retirement Obligations (AROs) represent legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability.

AROs have no impact on the income of the Utilities as the effects are offset by the establishment of regulatory assets and regulatory liabilities in order to reflect the ratemaking treatment of the related costs.

Progress Energy's, PEC's and PEF's total AROs at December 31, 2011, were $1.265 billion, $896 million, and $369 million, respectively. We calculated the present value of our AROs based on estimates which are dependent on subjective factors such as management's estimated retirement costs, the timing of future cash flows and the selection of appropriate discount and cost escalation rates. These underlying assumptions and estimates are made as of a point in time and are subject to change. These changes could materially affect the AROs, although changes in such estimates should not affect earnings, because these costs are expected to be recovered through rates.

Nuclear decommissioning AROs represent 95 percent, 97 percent, and 90 percent, respectively, of Progress Energy's, PEC's and PEF's total AROs at December 31, 2011. To determine nuclear decommissioning AROs, we utilize periodic site-specific cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our nuclear plants. Our regulators require updated cost estimates for nuclear decommissioning every five years. These cost studies 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. Changes in PEC's and PEF's nuclear decommissioning site-specific cost estimates or the use of alternative cost escalation or discount rates could be material to the nuclear decommissioning liabilities recognized.

PEC obtained updated cost studies for its nuclear plants in 2009, using 2009 cost factors, which PEC filed with the NCUC in 2010. If the site-specific cost estimates increased by 10 percent, PEC's AROs would have increased by $77 million. If the inflation adjustment increased 25 basis points, PEC's AROs would have increased by $169 million. Similarly, an increase in the discount rate of 25 basis points would have decreased PEC's AROs by $56 million.

PEF obtained an updated cost study for its nuclear plant in 2008, using 2008 cost factors, which was updated with the most currently available escalation rates in 2010 (See Note 5C). If the site-specific cost estimates increased by 10 percent, PEF's AROs would have increased by $32 million. If the inflation adjustment increased 25 basis points, PEF's AROs would have increased by $25 million. Similarly, an increase in the discount rate of 25 basis points would have decreased PEF's AROs by $21 million.

GOODWILL

As discussed in Note 9, goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility reporting units and our goodwill impairment tests are performed at the utility reporting unit level. The carrying amounts of goodwill at December 31, 2011 and 2010, for the PEC and PEF reporting units were $1.922 billion and $1.733 billion, respectively.

We calculate the fair value of our utility reporting units by considering various factors, including valuation studies based primarily on income and market approaches. Generally, more emphasis is applied to the income approach as substantially all of the Utilities' cash flows are from rate-regulated operations. In such environments, revenue requirements are adjusted periodically by regulators based on factors including levels of costs, sales volumes and costs of capital. Accordingly, the Utilities operate to some degree with a buffer from the direct effects, positive or negative, of significant swings in market or economic conditions.

The income approach uses discounted cash flow analyses to determine the fair value of the utility reporting units. The estimated future cash flows from operations are based on the Utilities' business plans, which reflect management's assumptions related to customer usage based on internal data and economic data obtained from third-party sources. The business plans assume the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of returns on equity, the timing of anticipated significant future capital investments, the anticipated earnings and returns related to such capital investments, continued recovery of cost of service and the renewal of certain contracts. Management also determines the appropriate discount rate for the utility reporting units based on the weighted average cost of capital for each utility, which takes into account both the cost of equity and pre-tax cost of debt. As each utility reporting unit has a different risk profile based on the nature of its operations, the discount rate for each reporting unit may differ.

The market approach uses implied market multiples derived from comparable peer utilities and market transactions to estimate the fair value of the utility reporting units. Peer utilities are evaluated based on percentage of revenues generated by regulated utility operations; percentage of revenues generated by electric operations; generation mix, including coal, gas, nuclear and other resources; market capitalization as of the valuation date; and geographic location. Comparable market transactions are evaluated based on the availability of financial transaction data and the nature and geographic location of the businesses or assets acquired, including whether the target company had a significant electric component. The selection of comparable peer utilities and market transactions, as well as the appropriate multiples from within a reasonable range, is a matter of professional judgment.

The calculations in both the income and market approaches are highly dependent on subjective factors such as management's estimate of future cash flows, the selection of appropriate discount and growth rates from a marketplace participant's perspective, and the selection of peer utilities and marketplace transactions for comparative valuation purposes. These underlying assumptions and estimates are made as of a point in time. If these assumptions change or should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, the fair value of the utility reporting units could be significantly different in future periods, which could result in a future impairment charge to goodwill.

Our 2011 annual test relied primarily on a market approach, which was based on the allocation of the fair value of the consideration to be received in the pending Merger to the utility reporting units. In addition, in response to uncertainty regarding CR3, management performed an additional analysis for the PEF reporting unit based primarily on income and market approaches as previously described. The results of our 2011 annual test of goodwill indicated that the fair values of the PEC and PEF reporting units substantially exceeded their respective carrying values, and therefore the carrying amounts of goodwill for the PEC and PEF reporting units were not impaired.

We monitor for events or circumstances, including financial market conditions and economic factors, that may indicate an interim goodwill impairment test is necessary. We would perform an interim impairment test should any events occur or circumstances change that would more likely than not reduce the fair value of a utility reporting unit below its carrying value.

UNBILLED REVENUE

As discussed in Note 1, we recognize electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utilities base revenues, primarily related to retail base revenues, earned when service has been delivered but not billed by the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for the electric utility revenues associated with unbilled sales is recognized. Unbilled retail revenues are estimated by applying a weighted average revenue/kWh for all customer classes to the number of estimated kWh delivered but not billed. The calculation of unbilled revenue is affected by factors that include fluctuations in energy demand for the unbilled period, seasonality, weather, customer usage patterns, price in effect for each customer class and estimated transmission and distribution line losses.

Amounts recorded as receivables on the Balance Sheets at December 31 related to unbilled revenues were as follows:

(in millions)	**2011**	2010
Progress Energy	**$ 157**	$ 223
PEC	**102**	136
PEF	**55**	87

INCOME TAXES

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. As discussed in Note 15, deferred income tax assets and liabilities represent the future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax-planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material. In accordance with GAAP, the uncertainty and judgment involved in the determination and filing of income taxes are accounted for by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. A two-step process is required: recognition of the tax benefit based on a "more-likely-than-not" threshold, and measurement of the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with the taxing authority.

PENSION COSTS

As discussed in Note 17A, we maintain qualified noncontributory defined benefit retirement (pension) plans. We also have supplementary defined benefit pension plans that provide benefits to higher-level employees. Our 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.

We have pension plan assets with a fair value of approximately $2.2 billion at December 31, 2011. For 2011, our expected rate of return on pension plan assets was 8.50%. The expected rate of return used in pension cost recognition is a long-term rate of return; therefore, we do not adjust that rate of return frequently. In 2011, we lowered the expected rate of return from the previously used 8.75%, due primarily to a shift in our investment strategy. A 25 basis point change in the expected rate of return for 2011 would have changed 2011 pension costs by approximately $5 million. For 2012, we have assumed an expected rate of return of 8.25%, which is reflected in the estimates of total 2012 pension costs discussed within this section.

Another factor affecting our pension costs, and sensitivity of the costs to plan asset performance, is the method selected to determine the market-related value of assets, i.e., the asset value to which the expected long-term rate of return is applied. 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. We have historically used a five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets. 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. Approximately 50 percent of our pension plan assets are subject to each of the two methods.

Due to a decrease in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate to calculate the present value of future benefit payments, we decreased the discount rate to 4.75% at December 31, 2011, from 5.65% at December 31, 2010, which will increase 2012 pension costs, all other factors remaining constant. Our discount rates are selected based on a plan-by-plan study, which matches our projected benefit payments to a high-quality corporate yield curve. Consistent with general market conditions, our plan assets experienced returns of approximately 5% in 2011. That negative asset performance, as compared to our expected asset returns, will result in increased pension costs in 2012, all other factors remaining constant. In addition, contributions to pension plan assets in 2011 and in 2012 will result in decreased pension costs in 2012 due to increased asset balances and resulting expected earnings on those assets, all other factors remaining constant.

Evaluations of our 2012 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2012 will be $110 million to $120 million, compared with $88 million recognized in 2011. A portion of net periodic benefit cost is capitalized as part of construction work in progress.

Since PEC and PEF participate in our pension plans, the general discussion above applies to PEC and PEF. PEC and PEF have not completed evaluating their 2012 pension costs. PEC estimates that the total cost recognized for pensions in 2012 will be $30 million to $35 million, compared with $24 million recognized in 2011. A 25 basis point change in the expected rate of return for 2011 would have changed PEC’s 2011 pension costs by approximately $3 million. PEF estimates that the total cost recognized for pensions in 2012 will be $50 million to $55 million, compared with $39 million recognized in 2011. A 25 basis point change in the expected rate of return for 2011 would have changed PEF’s 2011 pension costs by approximately $2 million.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

Our significant cash requirements arise primarily from the capital-intensive nature of the Utilities’ operations, including expenditures for environmental compliance. We typically rely upon our operating cash flow, substantially all of which is generated by the Utilities, commercial paper and credit facilities, and our ability to access the long-term debt and equity capital markets for sources of liquidity. As discussed in “Future Liquidity and Capital Resources” below, synthetic fuels tax credits will provide an additional source of liquidity as those credits are realized.

The majority of our operating costs are related to the Utilities. Most of these costs are recovered from ratepayers in accordance with various rate plans. We are allowed to recover certain fuel, purchased power and other costs incurred by PEC and PEF through their respective recovery clauses. The types of costs recovered through clauses vary by jurisdiction. Fuel price volatility and plant performance can lead to over- or under-recovery of fuel costs, as changes in fuel expense are not immediately reflected in fuel surcharges due to regulatory lag in setting the surcharges. As a result, fuel price volatility and plant performance can be both a source of and a use of liquidity resources, depending on what phase of the cycle of price volatility we are experiencing and/or how our plants are performing. Changes in the Utilities' fuel and purchased power costs may affect the timing of cash flows, but not materially affect net income. In addition, as discussed in "Future Liquidity and Capital Resources" below, the amount and timing of applicable CR3 repair and associated replacement power recovery from NEIL could impact borrowing needs.

As a registered holding company, our establishment of intercompany extensions of credit is subject to regulation by the FERC. Our subsidiaries participate in internal money pools, administered by PESC, to more effectively utilize cash resources and reduce external short-term borrowings. The utility money pool allows the Utilities to lend to and borrow from each other. A non-utility money pool allows our nonregulated operations to lend to and borrow from each other. The Parent can lend money to the utility and non-utility money pools but cannot borrow funds.

The Parent is a holding company and, as such, has no revenue-generating operations of its own. The primary cash needs at the Parent level are our common stock dividend, interest and principal payments on the Parent's $4.0 billion of senior unsecured debt and potentially funding the Utilities' capital expenditures through equity contributions. The Parent's ability to meet these needs is typically funded with dividends from the Utilities generated from their earnings and cash flows and, to a lesser extent, dividends from other subsidiaries; repayment of funds due to the Parent by its subsidiaries; the Parent's credit facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. During 2011, PEC paid dividends of $585 million and PEF paid dividends of $510 million to the Parent. PEC and PEF expect to pay dividends to the Parent in 2012. There are a number of factors that impact the Utilities' decision or ability to pay dividends to the Parent or to seek equity contributions from the Parent, including capital expenditure decisions and the timing of recovery of fuel and other pass-through costs. Therefore, we cannot predict the level of dividends or equity contributions between the Utilities and the Parent from year to year. The Parent could change its existing common stock dividend policy based upon these and other business factors.

Cash from operations, commercial paper issuances, borrowings under our credit facilities and/or long-term debt financings are expected to fund capital expenditures, long-term debt maturities and common stock dividends for 2012. In the event the Merger does not close by the Merger Agreement termination date of July 8, 2012, we may also use equity offerings or ongoing sales of common stock through the IPP and/or employee benefit and stock option plans to support our liquidity requirements (See "Financing Activities").

We have 23 financial institutions that support our combined $1.978 billion revolving credit facilities for the Parent, PEC and PEF, thereby limiting our dependence on any one institution. The credit facilities serve as back-ups to our commercial paper programs. To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2011, the Parent had no outstanding borrowings under its credit facility, $250 million of outstanding commercial paper and had issued $2 million of letters of credit supported by the revolving credit facility. At December 31, 2011, PEC and PEF had no outstanding borrowings under their respective credit facilities and $184 million and $233 million of outstanding commercial paper, respectively. Based on these outstanding amounts at December 31, 2011, there was a combined $1.309 billion available for additional borrowings.

At December 31, 2011, PEC and PEF had limited counterparty mark-to-market exposure for financial commodity hedges (primarily gas and oil hedges) due to spreading our concentration risk over a number of counterparties. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2011, the majority of the Utilities' open financial commodity hedges were in net mark-to-market liability positions. See Note 18A for additional information with regard to our commodity derivatives.

At December 31, 2011, we had limited mark-to-market exposure to certain financial institutions under pay-fixed forward starting swaps to hedge cash flow risk with regard to future financing transactions for the Parent, PEC and PEF. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2011, the sums of the Parent's, PEC's and PEF's open pay-fixed forward starting swaps were each in a net mark-to-market liability position. See Note 18B for additional information with regard to our interest rate derivatives.

The Wall Street Reform and Consumer Protection Act (H.R. 4173) includes, among other things, provisions related to the swaps and over-the-counter derivatives markets. Regulations related to these provisions to address items such as mandatory clearing and trading, reporting and capital and margin requirements have not yet been finalized. Given that we use commodity and interest rate hedges to mitigate commercial risk, we expect that we will be considered end users of these products under the law. Therefore, we expect that we will be exempt from the law's mandatory clearing and trading provisions, subject to certain reporting requirements. Capital and margin requirements for our interest rate and commodity hedges, as well as the law's impact on our counterparties and other market participants, are expected to be determined as more detailed rules and regulations are published. At this time, we do not expect the law to have a material impact on our financial condition, results of operations and cash flows. However, we cannot determine the impact until the final regulations are issued.

Our pension and nuclear decommissioning trust funds are managed by a number of financial institutions, and the assets being managed are diversified in order to limit concentration risk in any one institution or business sector.

We believe our internal and external liquidity resources will be sufficient to fund our current business plans. We will continue to monitor the credit markets to maintain an appropriate level of liquidity. Our ability to access the capital markets on favorable terms may be negatively impacted by credit rating actions. Risk factors associated with the capital markets and credit ratings are discussed below and in Item 1A, "Risk Factors."

The following discussion of our liquidity and capital resources is on a consolidated basis.

HISTORICAL FOR 2011 AS COMPARED TO 2010 AND 2010 AS COMPARED TO 2009

CASH FLOWS FROM OPERATIONS

Net cash provided by operations is the primary source used to meet operating requirements and a portion of capital expenditures. The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2011, 2010 and 2009. Net cash provided by operating activities for the three years ended December 31, 2011, 2010 and 2009, was $1.615 billion, $2.537 billion and $2.271 billion, respectively.

Net cash provided by operating activities for 2011 decreased when compared to 2010. The $922 million decrease in operating cash flow was primarily due to $308 million higher cash used for inventory, the $219 million less favorable impact of weather as previously discussed, a $205 million increase in pension plan funding, $86 million paid for interest rate hedges terminated in conjunction with the issuance of long-term debt in 2011 and $72 million decrease in NEIL reimbursements for replacement power costs due to the CR3 extended outage (See "Future Liquidity and Capital Resources – Regulatory Matters and Recovery of Costs – CR3 Outage"). The increase in cash used for inventory was primarily due to the higher coal purchases in 2011 reflecting anticipated winter consumption and inventory levels that remained high at year-end (due to lower natural gas prices), combined with higher 2010 consumption of existing inventory levels to meet system requirements resulting from favorable weather.

Net cash provided by operating activities increased $266 million for 2010, when compared to 2009. The increase was primarily due to the $203 million favorable impact of weather, partially offset by $78 million higher nuclear plant outage and maintenance costs included in O&M, both as previously discussed; $197 million lower cash used for inventory, primarily due to higher coal consumption in 2010 as a result of favorable weather that was fulfilled through the 2010 usage of inventory from year-end 2009; $154 million payment in 2009 due to a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates previously engaged in coal-based solid synthetic fuels operations (See Note 22D); $56 million net cash receipts for income taxes in 2010 compared to $87 million net cash payments for income taxes in 2009; and $121 million lower cash used for pension and other benefits, primarily due to a reduction of contributions made in 2010. These amounts were partially offset by a $2 million under-recovery of fuel in 2010 compared to a $290 million over-recovery of fuel in 2009 due to higher fuel costs and lower fuel rates in 2010 and $23 million of net payments of cash collateral to counterparties on derivative contracts in 2010 compared to $200 million net refunds of cash collateral in 2009.

The Utilities file annual requests with their respective state commissions seeking rate increases or decreases for fuel cost under- or over-recovery.

INVESTING ACTIVITIES

Net cash used by investing activities for the three years ended December 31, 2011, 2010 and 2009, was $2.212 billion, $2.400 billion and $2.532 billion, respectively.

Net cash used by investing activities decreased by $188 million for 2011, when compared to 2010. This decrease was primarily due to a $155 million decrease in gross property additions, primarily due to lower spending for environmental compliance and nuclear projects at PEF, the $42 million of smart grid grant reimbursements and $27 million of litigation judgment proceeds, partially offset by $24 million increase in restricted cash used to support letters of credit.

Net cash used by investing activities decreased by $132 million for 2010, when compared to 2009. This decrease was primarily due to a $74 million decrease in gross property additions, primarily due to lower spending for environmental compliance and nuclear projects at PEF, partially offset by PEC's increased capital expenditures at the Wayne County, New Hanover County and Harris generating facilities, and a $64 million increase in receipt of NEIL insurance proceeds for repairs due to the CR3 extended outage.

FINANCING ACTIVITIES

Net cash provided (used) by financing activities for the three years ended December 31, 2011, 2010 and 2009, was $216 million, $(251) million and $806 million, respectively. See Note 11 for details of debt and credit facilities.

Net cash provided by financing activities increased by $467 million for 2011, when compared to 2010. The increase is primarily due to a $902 million increase in proceeds from short-term and long-term debt, net of retirements, partially offset by $381 million net decrease in issuances of common stock, primarily related to the Parent's 2010 common stock sales under the IPP.

Net cash used by financing activities increased by $1.057 billion for 2010, when compared to 2009. The increase was primarily due to an $817 million decrease in proceeds from short-term and long-term debt, net of retirements, and a $192 million decrease in issuances of common stock, primarily related to a 2009 public offering.

Our financing activities are described below.

2012

- On February 15, 2012, the Parent's $478 million revolving credit agreement (RCA) was amended to extend the expiration date from May 3, 2012, to May 3, 2013, with its existing syndicate of 14 financial institutions. The Parent originally entered into the five-year RCA on May 3, 2006. On May 2, 2008, the expiration date of the RCA was extended to May 3, 2012. The Parent ratably reduced the size of the RCA from $1.130 billion to $500 million on October 15, 2010, and the RCA was further reduced to $478 million on May 3, 2011, following the expiration of one financial institution's credit commitment of $22 million (See "Credit Facilities and Registration Statements").

2011

- On January 21, 2011, the Parent issued $500 million of 4.40% Senior Notes due January 15, 2021. The net proceeds of $495 million, along with available cash on hand, were used to retire the $700 million outstanding aggregate principal balance of our 7.10% Senior Notes due March 1, 2011.
- On July 15, 2011, PEF paid at maturity $300 million of its 6.65% First Mortgage Bonds with proceeds from short-term debt borrowings.
- On August 18, 2011, PEF issued $300 million 3.10% First Mortgage Bonds due August 15, 2021. The net proceeds were used to repay a portion of outstanding short-term debt, of which $300 million was issued to repay PEF's July 15, 2011 maturity.
- On September 15, 2011, PEC issued $500 million 3.00% First Mortgage Bonds due September 15, 2021. A portion of the net proceeds was used to repay outstanding short-term debt and the remainder was used for general corporate purposes, including construction expenditures.

- Progress Energy issued approximately 2.0 million shares of common stock resulting in approximately $53 million in proceeds from the IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 2.0 million shares for proceeds of approximately $52 million issued under equity incentive plans. For 2011, the dividends paid on common stock were approximately $734 million.

2010

- On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with a portion of the proceeds from the $950 million of Senior Notes issued in November 2009.
- On March 25, 2010, PEF issued $250 million of 4.55% First Mortgage Bonds due 2020 and $350 million of 5.65% First Mortgage Bonds due 2040. Proceeds were used to repay the outstanding balance of PEF's notes payable to affiliated companies, to repay the maturity of PEF's $300 million 4.50% First Mortgage Bonds due June 1, 2010, and for general corporate purposes.
- On October 15, 2010, PEC and PEF each entered into new $750 million, three-year RCAs with a syndication of 22 financial institutions. The RCAs are used to provide liquidity support for PEC's and PEF's issuances of commercial paper and other short-term obligations, and for general corporate purposes. The RCAs will expire on October 15, 2013. The new $750 million RCAs replaced PEC's and PEF's $450 million RCAs, which were set to expire June 28, 2011, and March 28, 2011, respectively. Both $450 million RCAs were terminated effective October 15, 2010 (See "Credit Facilities and Registration Statements").
- Progress Energy issued approximately 12.2 million shares of common stock resulting in approximately $434 million in proceeds from the IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 11.2 million shares for proceeds of approximately $431 million issued for the IPP. For 2010, the dividends paid on common stock were approximately $718 million.

2009

- On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were approximately $523 million. On February 3, 2009, the Parent used $100 million of the proceeds to reduce its $600 million RCA balance outstanding at December 31, 2008, and the remainder was used for general corporate purposes.
- On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds was used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding short-term debt and for general corporate purposes.
- On March 19, 2009, the Parent issued an aggregate $750 million of Senior Notes consisting of $300 million of 6.05% Senior Notes due 2014 and $450 million of 7.05% Senior Notes due 2019. A portion of the proceeds was used to fund PEF's capital expenditures through an equity contribution with the remaining proceeds used for general corporate purposes.
- On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.
- On November 19, 2009, the Parent issued an aggregate $950 million of Senior Notes consisting of $350 million of 4.875% Senior Notes due 2019 and $600 million of 6.00% Senior Notes due 2039. The proceeds were used to retire at maturity the $100 million outstanding Series A Floating Rate Notes due January 15, 2010; to repay outstanding commercial paper balances; to pre-fund a portion of the $700 million aggregate principal amount due upon maturity of our 7.10% Senior Notes due March 1, 2011; and for general corporate purposes.
- During 2009, we repaid the November 2008 $600 million borrowing under our RCA.
- Progress Energy issued approximately 3.1 million shares of common stock resulting in approximately $100 million in proceeds from its IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 2.5 million shares for proceeds of approximately $100 million issued for the IPP and certain employee benefit plans. For 2009, the dividends paid on common stock were approximately $693 million.

SHORT-TERM DEBT

At December 31, 2011, Progress Energy had outstanding short-term debt consisting primarily of commercial paper borrowings totaling $671 million at a weighted average interest rate of 0.50%.

At the end of each month during the three months ended December 31, 2011, Progress Energy had a maximum short-term debt balance of $671 million and an average short-term debt balance of $484 million at a weighted average interest rate of 0.45%. Progress Energy's short-term debt during the three months ended December 31, 2011, consisted primarily of commercial paper borrowings.

At the end of each month during the year ended December 31, 2011, Progress Energy had a maximum short-term debt balance of $671 million and an average short-term debt balance of $286 million at a weighted average interest rate of 0.40%. Progress Energy's short-term debt during the year ended December 31, 2011, consisted primarily of commercial paper borrowings.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

Please review "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors," for a discussion of the factors that may impact any such forward-looking statements made herein.

The Utilities produce substantially all of our consolidated cash from operations. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our discontinued synthetic fuels operations historically produced significant net earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). A portion of these tax credits has yet to be realized in cash due to the difference in timing of when tax credits are recognized for financial reporting purposes and realized for tax purposes. At December 31, 2011, we have carried forward $865 million of deferred tax credits. Realization of these tax credits is dependent upon our future taxable income, which is expected to be generated primarily by the Utilities.

We expect to be able to meet our future liquidity needs through cash from operations, availability under our credit facilities and issuances of commercial paper and long-term debt, which are dependent on our ability to successfully access capital markets. In the event the Merger does not close by the Merger Agreement termination date of July 8, 2012, we may also use equity offerings or ongoing sales of common stock through our IPP and/or employee benefit and stock option plans to support our liquidity requirements.

Credit rating downgrades could negatively impact our ability to access the capital markets and respond to major events such as hurricanes. Our cost of capital could also be higher, which could ultimately increase prices for our customers. It is important for us to maintain our credit ratings and have access to the capital markets in order to reliably serve customers, invest in capital improvements and prepare for our customers' future energy needs.

We typically issue commercial paper to meet short-term liquidity needs. If liquidity conditions deteriorate and negatively impact the commercial paper market, we will need to evaluate other, potentially more expensive, options for meeting our short-term liquidity needs, which may include borrowing under our RCAs, issuing short-term notes and/or issuing long-term debt.

The current RCA for the Parent expires in May 2013 and the current RCAs for PEC and PEF expire in October 2013. In the event we enter into new credit facilities for the Parent, PEC or PEF we cannot predict the terms, prices, duration or participants in such facilities (See "Credit Facilities and Registration Statements").

Progress Energy and its subsidiaries have approximately $12.941 billion in outstanding long-term debt, including the $950 million current portion at December 31, 2011. Currently, approximately $860 million of the Utilities' debt obligations, approximately $620 million at PEC and approximately $240 million at PEF, are tax-exempt auction rate securities insured by bond insurance. These tax-exempt bonds have experienced and continue to experience failed auctions. Assuming the failed auctions persist, future interest rate resets on our tax-exempt auction rate bond portfolio will be dependent on the volatility experienced in the indices that dictate our interest rate resets and/or rating agency actions that may lower our tax-exempt bond ratings. In the event of a two notch downgrade of PEC's and/or PEF's senior secured debt rating by S&P, the ratings of such utility's tax-exempt bonds would be below A-, likely resulting in higher future interest rate resets. In the event of a two notch downgrade by Moody's, PEC's tax-exempt bonds will continue to be rated at or above A3 while PEF's would be below A3, likely resulting in higher future interest rate resets for PEF's tax-exempt bonds. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

The performance of the capital markets affects the values of the assets held in trust to satisfy future obligations under our defined benefit pension plans. Although a number of factors impact our pension funding requirements, a decline in the market value of these assets may significantly increase the future funding requirements of the obligations under our defined benefit pension plans. We expect to make contributions of $125 million to $225 million directly to pension plan assets in 2012 (See Note 17).

As discussed in "Liquidity and Capital Resources," "Capital Expenditures" and in "Other Matters – Environmental Matters," over the long term, compliance with environmental regulations and meeting the anticipated load growth at the Utilities, as described under "Other Matters – Energy Demand," will require the Utilities to make significant capital investments. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation. As discussed in "Other Matters – Nuclear – Potential New Construction," PEF will postpone major capital expenditures for the Levy project until after the NRC issues the COL, which is expected to be in 2013 if the current licensing schedule remains on track.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Substantially all derivative commodity instrument positions are subject to retail regulatory treatment. After settlement of the derivatives and consumption of the fuel, any realized gains or losses are passed through the fuel cost-recovery clause. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2011, have impacted the amount of collateral posted with counterparties. At December 31, 2011, we had posted approximately $147 million of cash collateral compared to $164 million of cash collateral posted at December 31, 2010. The majority of our financial hedge agreements will settle in 2012 and 2013. Additional commodity market price decreases could result in significant increases in the derivative collateral that we are required to post with counterparties. We continually monitor our derivative positions in relation to market price activity. As discussed in Note 18C, credit rating downgrades could also require us to post additional cash collateral for commodity hedges in a liability position, as certain derivative instruments require us to post collateral on liability positions based on our credit ratings.

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

At December 31, 2011, the current portion of our long-term debt was $950 million, including $500 million at PEC. We expect to fund the Parent's $450 million of Senior Notes due April 15, 2012, and PEC's $500 million of First Mortgage Bonds due July 15, 2012, with a combination of cash from operations, commercial paper borrowings and/or long-term debt issuances.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, including nuclear cost recovery, as discussed in Note 8 and "Other Matters – Regulatory Environment," and recovery of environmental costs, as discussed in Note 21 and in "Other Matters – Environmental Matters," may impact our future liquidity and financing activities. The impacts of these matters, including the timing of recoveries from ratepayers, can be both a source of and a use of future liquidity resources. Energy legislation enacted in recent years may impact our liquidity over the long term, including, among others, provisions regarding cost recovery, mandated renewable portfolio standards, DSM and EE.

Regulatory developments expected to have a material impact on our liquidity are discussed below.

PEC Cost-Recovery Filings

On June 29, 2011, the SCPSC approved PEC's request for an increase in the fuel rate charged to its South Carolina ratepayers. The $22 million increase, effective July 1, 2011, was driven by rising fuel prices.

On November 14, 2011, the NCUC approved a settlement agreement for an increase in the fuel rate PEC charges to its North Carolina ratepayers. The $85 million increase, effective December 1, 2011, was also driven by rising fuel prices.

Also on November 14, 2011, the NCUC approved PEC's request for an increase in the DSM and EE rate charges to its North Carolina ratepayers. The $24 million increase was effective December 1, 2011.

PEC Other Matters

The NCUC has issued Certificates of Public Convenience and Necessity allowing PEC to proceed with plans to construct an approximately 950-MW generating facility at a site in Wayne County, N.C., projected to be in service by January 2013 and an approximately 620-MW generating facility at a site in New Hanover County, N.C., projected to be in service by December 2013.

CR3 Outage

The preliminary cost estimate as filed with the FPSC on June 27, 2011, for the selected repair option to return CR3 to service is between $900 million and $1.3 billion. Engineering design of the final repair is under way. PEF will update the current estimate as this work is completed.

PEF maintains insurance for property damage and incremental costs of replacement power resulting from prolonged accidental outages through NEIL as discussed in Note 5D. NEIL has confirmed that the CR3 initial delamination is a covered accident but has not yet made a determination as to coverage for the second delamination. Following a 12-week deductible period, the NEIL program provided reimbursement for replacement power costs for 52 weeks at $4.5 million per week, through April 9, 2011. An additional 71 weeks of coverage, which runs through August 2012, is provided at $3.6 million per week. Accordingly, the NEIL program provides replacement power coverage of up to $490 million per event. Actual replacement power costs have exceeded the insurance coverage through December 31, 2011. PEF anticipates that future replacement power costs will continue to exceed the insurance coverage. PEF also maintains insurance coverage through NEIL's accidental property damage program, which provides insurance coverage up to $2.25 billion with a $10 million deductible per claim.

PEF is continuing to work with NEIL for recovery of applicable repair costs and associated replacement power costs. PEF has not yet received a definitive determination from NEIL about the insurance coverage related to the second delamination. In addition, no replacement power reimbursements were received from NEIL in the second half of 2011. These considerations led us to conclude that at December 31, 2011, it was not probable that NEIL will voluntarily pay the full coverage amounts we believe they owe under the applicable insurance policies. Given the circumstances, accounting standards require full recovery to be probable to recognize an insurance receivable. Therefore, PEF has suspended recording any further insurance receivables from NEIL related to the second delamination and removed the associated $222 million NEIL receivable. PEF recorded a corresponding $154 million addition to its deferred fuel regulatory asset and a $68 million addition to construction work in progress. See "2012 Settlement Agreement" below for discussion of PEF's ability to recover prudently incurred fuel and purchased power costs and CR3 repair costs. Negotiations continue with NEIL regarding coverage associated with the second delamination and PEF continues to believe that all applicable costs associated with bringing CR3 back into service are covered under all insurance policies.

The following table summarizes the CR3 replacement power and repair costs and recovery through December 31, 2011:

(in millions)	Replacement Power Costs	Repair Costs
Spent to date	$ 478	$ 258
NEIL proceeds received	(162)	(136)
Insurance receivable at December 31, 2011, net	(55)	(3)
Balance for recovery[(a)]	$ 261	$ 119

(a) See “2012 Settlement Agreement” and “PEF Cost Recovery Filings” below and Note 8C for discussion of PEF’s ability to recover prudently incurred fuel and purchase power costs and CR3 repair costs.

PEF believes the actions taken and costs incurred in response to the CR3 delamination have been prudent and, accordingly, considers replacement power and capital costs not recoverable through insurance to be recoverable through its fuel cost-recovery clause or base rates. Additional replacement power costs and repair and maintenance costs incurred until CR3 is returned to service could be material. Additionally, we cannot be assured that CR3 can be repaired and brought back to service until full engineering and other analyses are completed.

PEF 2012 Settlement Agreement

On February 22, 2012, the FPSC approved a comprehensive settlement agreement between PEF, the Florida Office of Public Counsel and other consumer advocates. The agreement, which will continue through the last billing cycle of December 2016, addresses three principal matters: cost recovery for Levy, the CR3 delamination prudence review pending before the FPSC and certain base rate issues. The agreement sets the Levy cost-recovery factor at a fixed amount during the term of the settlement and also allows PEF to recover investment and replacement power costs for CR3 in various circumstances. The parties to the agreement have waived or limited their rights to challenge the prudence of various costs related to CR3. The agreement provides for a $150 million annual increase in revenue requirements effective with the first billing cycle of January 2013, while maintaining the current ROE range of 9.5 percent to 11.5 percent. In the month following CR3’s return to commercial service, PEF’s ROE range will increase to 9.7 percent to 11.7 percent. Additionally, PEF will refund $288 million to customers through the fuel clause over four years, beginning in 2013. See Note 8C for additional provisions of the 2012 settlement agreement.

PEF 2010 Settlement Agreement

On June 1, 2010, the FPSC approved a settlement agreement between PEF and the interveners, with the exception of the Florida Association for Fairness in Ratemaking, to the 2009 rate case. As part of the settlement, PEF withdrew its motion for reconsideration of the rate case order. Among other provisions, under the terms of the settlement agreement, PEF will maintain base rates at current levels through the last billing cycle of 2012. Among other provisions, the settlement agreement also authorized PEF the opportunity to earn a ROE of up to 11.5 percent and provides that if PEF’s actual retail base rate earnings fall below a 9.5 percent ROE on an adjusted or pro forma basis, as reported on a historical 12-month basis during the term of the agreement, PEF may seek general, limited or interim base rate relief, or any combination thereof, subject to certain conditions. The settlement agreement does not preclude PEF from requesting the FPSC to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been or are presently recovered through cost-recovery clauses or surcharges; or (b) that are incremental costs not currently recovered in base rates, which the legislature or FPSC determines are clause recoverable; or (c) which are recoverable through base rates under the nuclear cost-recovery legislation or the FPSC’s nuclear cost-recovery rule. Finally, PEF will be allowed to recover the costs of named storms on an expedited basis after depletion of the storm damage reserve. Specifically, 60 days following the filing of a cost-recovery petition with the FPSC and based on a 12-month recovery period, PEF can begin recovery, subject to refund, through a surcharge of up to $4.00 per 1,000 kWh on monthly residential customer bills for storm costs. In the event the storm costs exceed that level, any excess additional costs will be deferred and recovered in a subsequent year or years as determined by the FPSC. Additionally, the order approving the settlement agreement allows PEF to use the surcharge to replenish the storm damage reserve to $136 million, the level as of June 1, 2010, after storm costs are fully recovered.

PEF Cost-Recovery Filings

On November 22, 2011, the FPSC approved a net increase of the total fuel-cost recovery by $162 million. The net increase, effective January 1, 2012, was driven primarily by rising fuel prices partially offset by lower anticipated costs associated with Levy and the deferral of 2011 and 2012 estimated costs associated with PEF's CR3 uprate project. Within the fuel clause, PEF received approval to collect, subject to refund, replacement power costs related to the CR3 nuclear plant outage.

On November 22, 2011, the FPSC approved PEF's request to increase the ECRC by $24 million, effective January 1, 2012.

CAPITAL EXPENDITURES

We expect to make significant capital investments to meet anticipated load growth and environmental standards. We are currently constructing new generating facilities in the Carolinas and potentially will construct new baseload generating facilities in the Carolinas and Florida that will be placed in service toward the middle of the next decade.

Total cash from operations and proceeds from long-term debt and equity issuances provided the funding for our 2011 capital expenditures, and those sources are expected to fund our forecasted capital expenditures.

As shown in the following table, we expect the majority of our capital expenditures to be incurred at our regulated operations. AFUDC – borrowed funds represents the debt costs of capital funds necessary to finance the construction of new regulated plant assets.

	Actual	Forecasted		
(in millions)	**2011**	2012	2013	2014
Regulated capital expenditures[a]	**$ 1,981**	$ 1,925	$ 1,920	$ 1,930
Nuclear fuel expenditures	**226**	160	220	255
AFUDC – borrowed funds	**(32)**	(35)	(30)	(20)
Other capital expenditures	**16**	30	30	30
Total before potential nuclear construction	**2,191**	2,080	2,140	2,195
Potential nuclear construction[b][c]	**63**	50-150	50-150	TBD
Total	**$ 2,254**	$ 2,130-2,230	$ 2,190-2,290	$ 2,195

(a) Excludes estimates for the repair of the CR3 containment building and the completion of the extended power uprate project.

(b) Expenditures for potential nuclear construction are net of AFUDC – borrowed funds.

(c) Project spending for 2014 and beyond will be determined once the timing for the receipt of the COL is known and more detailed estimates have been developed based on the schedule shifts and other factors.

Regulated capital expenditures for 2012, 2013 and 2014 in the previous table include approximately $60 million, $95 million and $200 million, respectively, for environmental compliance. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance strategy and related recovery of costs. Regulated capital expenditures exclude estimates for the repair of the CR3 containment building and the completion of the extended power uprate project. Estimates of these projects will be developed upon the completion of ongoing engineering and project planning, the resolution of negotiations with NEIL regarding insurance coverage of the second CR3 delamination and final decisions regarding repair versus retirement.

Potential nuclear construction expenditures are primarily related to PEF's Levy project. Because of announced schedule shifts, we negotiated an amendment to the Levy EPC agreement (See discussion under "Other Matters – Nuclear – Potential New Construction"). The forecasted capital expenditures presented in the previous table reflect the announced schedule shift. Project spending for 2014 and beyond will be determined once the timing for the receipt of the COL is known and more detailed estimates have been developed based on this and other factors. Future nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages of joint ownership. These expenditures are subject to cost-recovery provisions in the Utilities' respective jurisdictions (See Note 8C).

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.

CREDIT FACILITIES AND REGISTRATION STATEMENTS

At December 31, 2011 and 2010, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2011 and 2010, we had no outstanding borrowings under our credit facilities. We are required to pay fees to maintain our credit facilities.

The following tables summarize our RCAs and available capacity at December 31:

(in millions)		**Total**	**Outstanding**	**Reserved[(a)]**	**Available**
2011					
Parent	**Five-year (expiring 5/3/12)[(b) (c)]**	**$ 478**	**$ -**	**$ 252**	**$ 226**
PEC	**Three-year (expiring 10/15/13)**	**750**	**-**	**184**	**566**
PEF	**Three-year (expiring 10/15/13)**	**750**	**-**	**233**	**517**
Total credit facilities		**$ 1,978**	**$ -**	**$ 669**	**$ 1,309**
2010					
Parent	Five-year (expiring 5/3/12)	$ 500	$ -	$ 31	$ 469
PEC	Three-year (expiring 10/15/13)	750	-	-	750
PEF	Three-year (expiring 10/15/13)	750	-	-	750
Total credit facilities		$ 2,000	$ -	$ 31	$ 1,969

(a) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2011 and 2010, the Parent had issued $2 million and $31 million, respectively, of letters of credit supported by the RCA. On December 31, 2011, the Parent, PEC and PEF had $250 million, $184 million and $233 million, respectively, of outstanding commercial paper supported by their RCAs.

(b) Approximately $22 million of the $500 million expired May 3, 2011.

(c) On February 15, 2012, the Parent's $478 million credit facility was amended to extend the expiration date to May 3, 2013.

All of the revolving credit facilities were arranged through a syndication of financial institutions. See Note 12 for additional discussion of our credit facilities.

The RCAs provide liquidity support for issuances of commercial paper and other short-term obligations. We expect to continue to use commercial paper issuances as a source of liquidity as long as we maintain our current short-term ratings. Fees and interest rates under our RCAs are based upon the respective credit ratings of the Parent's, PEC's and PEF's long-term unsecured senior noncredit-enhanced debt.

All of the credit facilities include defined maximum total debt-to-total capital ratio (leverage) covenants, which we were in compliance with at December 31, 2011. We are currently in compliance and expect to continue to be in compliance with these covenants. See Note 12 for a discussion of the credit facilities' financial covenants. At December 31, 2011, the calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, are as disclosed in Note 12.

On November 16, 2011, the Parent filed a shelf registration statement with the SEC for its IPP, which became effective upon filing with the SEC. The registration statement is effective for three years and registers 10 million shares of common stock for issuance pursuant to the IPP. In addition, the Parent, as a well-known seasoned issuer, typically files a shelf registration statement with the SEC under which it may issue an unlimited number or amount of various securities, including senior debt securities, junior subordinated debentures, common stock, preferred stock, stock purchase contracts and stock purchase units. Both PEC and PEF typically file shelf registration statements with the SEC under which they may issue an unlimited number or amount of various long-term debt securities and preferred stock. We expect to file a new combined shelf registration statement with the SEC, as our previously filed shelf registration statement for these securities expired November 17, 2011.

Both PEC and PEF can issue first mortgage bonds under their respective first mortgage bond indentures based on property additions, retirements of first mortgage bonds and the deposit of cash if certain conditions are satisfied. At December 31, 2011, PEC and PEF could issue up to approximately \$6.8 billion and \$2.9 billion of first mortgage bonds, respectively, based on property additions and retirements of previously issued first mortgage bonds. Most first mortgage bond issuances by PEC and PEF require that adjusted net earnings be at least twice the annual interest requirement for bonds currently outstanding and to be outstanding. At December 31, 2011, PEC's and PEF's ratios of adjusted net earnings to annual interest requirement on outstanding first mortgage bonds were 5.0 times and 1.7 times, respectively. PEF's ratio of net earnings to the annual interest requirement for bonds outstanding, as defined in PEF's mortgage, was below 2.0 times at December 31, 2011. PEF's 2011 net earnings were impacted by a \$288 million charge recorded in December 2011 for amounts to be refunded to customers (See Note 8C). Until this ratio, which is calculated based on results for 12 consecutive months, is above 2.0 times, PEF's capacity to issue first mortgage bonds is limited to \$300 million based on retirements of previously issued first mortgage bonds. In the event PEF's long-term debt requirements exceed its first mortgage bond capacity, it could issue unsecured debt.

CAPITALIZATION RATIOS

The following table shows each component of capitalization as a percentage of total capitalization at December 31, 2011 and 2010. In addition to total equity and preferred stock, total capitalization includes the following in total debt: long-term debt, net, long-term debt, affiliate, current portion of long-term debt, short-term debt and capital lease obligations.

	2011	2010
Total equity	**41.9%**	43.6%
Preferred stock	**0.4%**	0.4%
Total debt	**57.7%**	56.0%

CREDIT RATING MATTERS

Our credit ratings reflect the current views of the rating agencies, and no assurances can be given that our ratings will continue for any given period of time. However, we monitor our financial condition as well as market conditions that could ultimately affect our credit ratings.

Credit rating downgrades could negatively impact our ability to access the capital markets and respond to major events such as hurricanes. Our cost of capital could also be higher, which could ultimately increase prices for our customers. It is important for us to maintain our credit ratings and have access to the capital markets in order to reliably serve customers, invest in capital improvements and prepare for our customers' future energy needs (See Item 1A, "Risk Factors").

As discussed in Note 18C, credit rating downgrades could also require us to post additional cash collateral for commodity hedges in a liability position as certain derivative instruments require us to post collateral on liability positions based on our credit ratings.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

Our off-balance sheet arrangements and contractual obligations are described below.

GUARANTEES

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include standby letters of credit, surety bonds, performance obligations for trading operations and guarantees of certain subsidiary credit obligations. At December 31, 2011, we have issued $477 million of guarantees for future financial or performance assurance, including $19 million at PEC. Included in this amount is $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries issued by the Parent (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

At December 31, 2011, we have issued guarantees and indemnifications of certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations, as discussed in Note 22C.

MARKET RISK AND DERIVATIVES

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

CONTRACTUAL OBLIGATIONS

We are party to numerous contracts and arrangements obligating us 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. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented in the following table are estimates and therefore will likely differ from actual purchase amounts. Further disclosure regarding our contractual obligations is included in the respective notes to the Consolidated Financial Statements. We take into consideration the future commitments when assessing our liquidity and future financing needs.

The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2011, 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 (See Note 12)[a]	$ 12,999	$ 950	$ 1,130	$ 1,300	$ 9,619
Interest payments on long-term debt[b]	9,749	666	1,224	1,097	6,762
Capital lease obligations (See Note 22B)[c]	423	34	74	64	251
Operating leases (See Note 22B)[c]	1,400	67	193	186	954
Fuel and purchased power (See Note 22A)[d]	20,248	2,783	4,518	3,406	9,541
Other purchase obligations (See Note 22A)[e]	1,676	484	420	159	613
Minimum pension funding requirements[f]	423	119	208	88	8
Other postretirement benefits[g]	511	43	93	101	274
Uncertain tax positions[h]	-	-	-	-	-
Other commitments[i]	78	13	26	26	13
Total	$ 47,507	$ 5,159	$ 7,886	$ 6,427	$ 28,035

(a) Our maturing debt obligations are generally expected to be repaid with cash from operations or refinanced with new debt issuances in the capital markets.

(b) Interest payments on long-term debt are based on the interest rate effective at December 31, 2011.

(c) Amounts include certain related executory cost commitments.

(d) Essentially all fuel and certain purchased power costs incurred by the Utilities are eligible for recovery through cost-recovery clauses in accordance with state and federal regulations and therefore do not require separate liquidity support. Amounts exclude precedent and conditional contracts of $1.510 billion at PEC. (See Note 22A.)

(e) The future construction obligations presented in this table for Progress Energy exclude PEF's Levy EPC agreement. The EPC agreement includes provisions for termination. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. As discussed in Note 8C, in 2010 PEF identified a schedule shift in the Levy project, and major construction activities on Levy have been postponed until after the NRC issues the COL for the plants, which is expected in 2013 if the current licensing schedule remains on track. We executed an amendment to the EPC agreement in 2010 due to the schedule shifts. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF completed vendor negotiations in July 2011 to continue or suspend purchase orders for long lead time equipment without material fees or charges. Prior to the EPC amendment, estimated payments and associated escalations were $8.608 billion for the multi-year contract and did not assume any joint ownership. Because we have executed an amendment to the EPC agreement and anticipate negotiating additional amendments upon receipt of the COL, we cannot currently predict when those obligations will be satisfied or the magnitude of any change. PEF has continued with selected components of long lead time equipment. Work was suspended on the remaining long lead time equipment items, which have total remaining estimated payments and associated escalations of approximately $1.250 billion included in the previously discussed $8.608 billion. We cannot predict the outcome of this matter.

(f) Represents the projected minimum required contributions to the qualified pension trusts for a total of 10 years. These amounts are subject to change significantly based on factors such as pension asset earnings and market interest rates.

(g) Represents projected benefit payments for a total of 10 years related to our postretirement health and life plans and are subject to change based on factors such as experienced claims and general health care cost trends.

(h) Uncertain tax positions of $173 million are not reflected in this table as we cannot predict when open income tax years will close with completed examinations. It is reasonably possible that unrecognized tax benefits will decrease by approximately $25 million during the 12-month period ending December 31, 2012, due to IRS review of open tax years.

(i) By NCUC order, in 2008, PEC began transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of the original $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

OTHER MATTERS

ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations. Environmental laws and regulations frequently change and the ultimate costs of compliance cannot always be precisely estimated. The table below summarizes the status of key environmental regulations that impact or may impact the Utilities. The table is followed by a detailed discussion of each regulation.

Status	Primarily Regulates	Compliance Strategy
	Impacting Solid Waste	
Coal Combustion Residuals		
Final rule expected in late 2012	Storage, use and disposal of coal ash and scrubber sludge	Proposed rule included two significantly different options. Compliance method cannot be determined until the rule is final.
	Impacting Air Quality	
NC Clean Smokestacks		
In effect	NOx, SO_2	Evaluating strategy for compliance subsequent to 2013
CAIR / CSAPR		
CAIR in effect pending resolution of appeal of CSAPR	NOx, SO_2	Previously installed air pollution controls and fleet modernization projects, and use of emission allowances
NC Mercury		
NC-specific requirements in effect	Mercury	Federal EGU MACT rule compliance
EGU MACT		
Final rule published February 16, 2012, and will become effective April 16, 2012	Mercury and other hazardous metals, acid gases, hydrogen fluoride, dioxin/furan	Previously installed air pollution controls and fleet modernization projects largely address for PEC; for PEF, additional controls and/or fleet modernization required
GHG New Source Performance Standards		
Proposed rule first quarter 2012	GHGs	Case-by-case determination for new units
CAVR – BART provisions		
Effective 2013	NOx, SO_2 and particulate matter	Assessing BART impact; EPA may allow CSAPR compliance to fulfill BART requirements
NAAQS		
In effect	Ozone, NO_2, SO_2 and particulate matter	Currently in compliance. Additional controls may be necessary if nonattainment is determined

Impacting Water Quality		
316(b)		
Final rules are expected in late July 2012	Cooling water intake structures for steam-electric power plants	Modification of traveling screens; assessment of environmental impacts and alternative technologies for reducing those impacts; and possible installation of new technologies
Effluent Guideline Revisions		
Proposed revisions anticipated in late July 2012	Wastewater discharges from steam-electric plants	Cannot be determined until final rule is issued

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the CERCLA authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liability. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida or potentially responsible parties (PRP) groups. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 8 and 21). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted. Hazardous and solid waste management matters are discussed in detail in Note 21A.

We accrue costs to the extent our liability is probable and the costs can be reasonably estimated. Because the extent of environmental impact, allocation among PRPs for all sites, remediation alternatives (which could involve either minimal or significant efforts), and concurrence of the regulatory authorities have not yet reached the stage where a reasonable estimate of the remediation costs can be made, we cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is probable that current estimates could change and additional losses, which could be material, may be incurred in the future.

The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion residuals, primarily ash, from each of the Utilities' coal-fired plants. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or groundwater protection environmental controls. In 2010, the EPA proposed two options for new rules to regulate coal combustion residuals. The first option would create a comprehensive program of federally enforceable requirements for coal combustion residuals management and disposal under federal hazardous waste rules. The other option would have the EPA set performance standards for coal combustion residuals management facilities and regulate disposal of coal combustion residuals as nonhazardous waste (as most states do now). The EPA did not identify a preferred option. Under both options, the EPA may leave in place a regulatory exemption for approved beneficial uses of coal combustion residuals that are recycled. A final rule is expected in 2012. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures under existing regulations. These issues are also under evaluation by state agencies. Certain regulated chemicals have been measured in wells near our ash ponds at levels above groundwater quality standards. Additional monitoring and investigation will be conducted. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary. We cannot predict the outcome of this matter.

AIR QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which likely would result in increased capital expenditures and O&M expense. Control equipment installed for compliance with then-existing or proposed laws and regulations, which are discussed below, may address some of the issues outlined. PEC and PEF have been developing an integrated compliance strategy to meet these evolving requirements. However, the outcome of these matters cannot be predicted.

Clean Smokestacks Act

The 2002 enactment of the Clean Smokestacks Act requires the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,000 MW of coal-fired generation capacity in North Carolina affected by the Clean Smokestacks Act. PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions have been placed in service. PEC implemented a plan to retire, by the end of 2013, its coal-fired generating facilities in North Carolina (originally totaling 1,500 MW) that do not have scrubbers and replace the generation capacity with new natural gas-fueled generating facilities, which should enable the utility to comply with the final Clean Smokestacks Act SO_2 emissions target that begins in 2013. The first unit was retired in 2011. We anticipate that PEC will maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

O&M expense increases with the operation of pollution control equipment due to the cost of reagents, additional personnel and general maintenance associated with the pollution control equipment. PEC is allowed to recover the cost of reagents and certain other costs under its fuel clause; the North Carolina retail portion of all other O&M expense is currently recoverable through base rates. In 2009, the SCPSC issued an order allowing PEC to begin deferring as a regulatory asset the depreciation expense that PEC incurs on its environmental compliance control facilities as well as the incremental O&M expense that PEC incurs in connection with its environmental compliance control facilities.

Clean Air Interstate Rule/Cross-State Air Pollution Rule

The CAIR, issued by the EPA, required the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO_2 emissions. The CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2. States were required to adopt rules implementing the CAIR, and the EPA approved the North Carolina CAIR, the South Carolina CAIR and the Florida CAIR. A 2008 decision by the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) remanded the CAIR without vacating it for the EPA to conduct further proceedings.

On July 7, 2011, the EPA issued the CSAPR to replace the CAIR. The CSAPR, slated to take effect on January 1, 2012, contains new emissions trading programs for NOx and SO_2 emissions as well as more stringent overall emissions targets in 27 states, including North Carolina, South Carolina and Florida. A number of parties, including groups which PEC and PEF are members of, filed petitions for reconsideration and stay of, as well as legal challenges to, the CSAPR. On December 30, 2011, the D.C. Court of Appeals issued an order staying the implementation of the CSAPR, pending a decision by the court resolving the challenges to the rule. Oral argument for the CSAPR litigation has been scheduled for April 13, 2012. As a result of the stay of CSAPR, the CAIR will remain in effect. The EPA issued the CSAPR as four separate programs, including the NOx annual trading program, the NOx ozone season trading program, the SO_2 Group 1 trading program and the SO_2 Group 2 trading program. If the CSAPR is upheld, North Carolina and South Carolina are included in the NOx and SO_2 annual trading programs, as well as the NOx ozone season program. North Carolina remains classified as a Group 1 state, which will require additional NOx and SO_2 emission reductions beginning in January 2014. South Carolina remains classified as a Group 2 state with no additional reductions required. Under the CSAPR, Florida is subject only to the NOx ozone season program. We cannot predict the outcome of this matter.

Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC and PEF are positioned to comply with the CSAPR without the need for significant capital expenditures. The air quality controls installed to comply with NOx and SO_2 requirements under certain sections of the Clean Air Act (CAA) and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, largely address the CAIR and CSAPR requirements for NOx and SO_2 for our North Carolina units at PEC. NOx and SO_2 emission control equipment are in service at PEF's Crystal River Unit No. 4 and Crystal River Unit No. 5 (CR4 and CR5), and we plan to continue compliance with the CAIR in 2012 through a combination of emission controls, continued use of natural gas at applicable facilities and use of emission allowances.

Under an agreement with the Florida Department of Environmental Protection (FDEP), PEF will retire Crystal River Units No. 1 and No. 2 coal-fired steam units (CR1 and CR2) and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was originally anticipated to be around 2020. As discussed in Note 8C and "Other Matters – Nuclear – Potential New Construction," major construction activities for Levy are being postponed until after the NRC issues the Levy COL. As required, PEF has advised the FDEP of developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated date. We are currently evaluating the impacts of the Levy schedule on PEF's compliance with environmental regulations. We cannot predict the outcome of this matter.

Mercury Regulation

In 2008, the D.C. Court of Appeals vacated the Clean Air Mercury Rule (CAMR). As a result, the EPA subsequently announced that it would develop MACT standards. The U.S. District Court for the District of Columbia issued an order requiring the EPA to issue a final MACT standard for power plants. On February 16, 2012, the EPA published the final EGU MACT. The rule will become effective on April 16, 2012. Compliance is due in three years with provisions for a one-year extension from state agencies on a case-by-case basis. The EGU MACT contains stringent emission limits for mercury, non-mercury metals and acid gases from coal-fired units and hazardous air pollutant metals, acid gases and hydrogen fluoride from oil-fired units. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC is relatively well positioned to comply with the EGU MACT. However, PEF will be required to complete additional emissions controls and/or fleet modernization projects in order to meet the compliance timeframe for the EGU MACT. We are continuing to evaluate the impacts of the EGU MACT on the Utilities. We anticipate that compliance with the EGU MACT will satisfy the North Carolina mercury rule requirements for PEC. The outcome of these matters cannot be predicted.

Clean Air Visibility Rule

The EPA's Clean Air Visibility Rule (CAVR) requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in certain specially protected areas, including national parks and wilderness areas, designated as Class I areas. To help restore visibility in those areas, states must require the identified facilities to install best available retrofit technology (BART) to control their emissions. PEC's BART-eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF's BART-eligible units are Anclote Units No. 1 and No. 2, CR1 and CR2. The reductions associated with BART begin in 2013. As discussed in Note 8B, Sutton Unit No. 3 is one of the coal-fired generating units that PEC plans to replace with combined cycle natural gas-fueled electric generation. As discussed previously, PEF and the FDEP announced an agreement under which PEF will retire CR1 and CR2 as coal-fired units.

The CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of the CAIR could be used by states as a BART substitute to fulfill BART obligations, but the states could require the installation of additional air quality controls if they did not achieve reasonable progress in improving visibility. The D.C. Court of Appeals' decision remanding the CAIR maintained its implementation such that CAIR satisfies BART for NOx and SO_2. In addition, the EPA has indicated that it intends to finalize a rule by spring 2012 that addresses its determination whether, for power plants, meeting the requirements in the CSAPR will fulfill the BART requirements for SO_2 and NOx under the regional haze program. Under subsequent implementation of CSAPR, CAVR compliance eventually will require consideration of SO_2 emissions in addition to particulate matter emissions for PEF's BART-eligible units, because Florida will no longer be subject to the current CAIR SO_2 emissions provisions. We are assessing the potential impact of BART and its implications with respect to our plans and estimated costs to comply with the CAVR. The FDEP finalized a Regional Haze implementation rule that goes beyond BART by requiring sources significantly impacting visibility in Class I areas to install additional controls by December 31, 2017. However, in the spring of 2010 the EPA indicated that the Reasonable Further Progress portion of the Regional Haze implementation rule is not approvable. The FDEP is in the process of amending the rule by removing the Reasonable Further Progress provision, including the December 31, 2017 deadline for installation of additional controls, and instead will rely on current federal programs to achieve improvement in visibility. In November 2011, the EPA announced a settlement that sets a schedule for action on the regional haze state implementation plans submitted by the states. The deadlines in the consent decree provide that all final EPA actions on the regional haze state implementation plans are to occur no later than November 15, 2012. The outcome of these matters cannot be predicted.

Compliance Strategy

Both PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, the CSAPR, the CAVR, mercury regulation and related air quality regulations. The air quality controls installed to comply with NOx and SO_2 requirements under certain sections of the CAA and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, resulted in a reduction of the costs to meet PEC's CAIR and CSAPR requirements.

PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions and PEF's environmental compliance projects under the first phase of CAIR are in service.

The FPSC approved PEF's petition to develop and implement an Integrated Clean Air Compliance Plan to comply with the CAIR, CAMR and CAVR and for recovery of prudently incurred costs necessary to achieve this strategy through the ECRC (see previous discussion regarding the vacating of the CAMR and remanding of the CAIR and its potential impact on CAVR). PEF's April 1, 2011 filing with the FPSC for true-up of final 2010 environmental costs included a review of the Integrated Clean Air Compliance Plan, which reconfirmed the efficacy of the recommended plan and total estimated project cost of approximately $1.1 billion to plan, design, build and install pollution control equipment at CR4 and CR5, which has been placed in service. PEF does not currently plan to install air pollution control equipment at the Anclote Plant as previously anticipated in its approved Integrated Clean Air Compliance Plan. Additional costs may be incurred if pollution controls are required in order to comply with the requirements of the CAVR, as discussed previously, or to meet compliance requirements of the CSAPR. Subsequent rule interpretations, increases in the underlying material, labor and equipment costs, equipment availability, or the unexpected acceleration of compliance dates, among other things, could result in significant increases in our estimated costs to comply and acceleration of some projects. The outcome of this matter cannot be predicted.

Environmental Compliance Cost Estimates

Risk factors regarding environmental compliance cost estimates are discussed in Item 1A, "Risk Factors." Costs to comply with environmental laws and regulations are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. Our estimates of capital expenditures to comply with environmental laws and regulations are subject to periodic review and revision and may vary significantly. PEC is continuing to evaluate various design, technology and new generation options that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013. Additional compliance plans for PEC and PEF to meet the requirements of the CSAPR have not been completed. Compliance plans and costs to meet the requirements of the CAVR are being reassessed, and we cannot predict the impact that the EPA's further proceedings will have on our compliance with the CAVR requirements. Compliance plans to meet the requirements of the EGU MACT are being developed. Compliance plans to meet the requirements of a revised or new implementing rule under Section 316(b) of the Clean Water Act (Section 316(b)), as discussed below, will be determined upon finalization of the rule. The timing and extent of the costs for future projects will depend upon final compliance strategies. However, we believe that future costs to comply with new or subsequent rule interpretations could be significant.

North Carolina Attorney General Petition under Section 126 of the Clean Air Act

In 2004, the North Carolina attorney general filed a petition with the EPA, under Section 126 of the CAA, asking the federal government to force fossil fuel-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 Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. In

2006, the EPA issued a final response denying the petition, and the North Carolina attorney general filed a petition in the D.C. Court of Appeals seeking a review of the agency's denial. In 2009, the D.C. Court of Appeals remanded the EPA's denial to the agency for reconsideration. The outcome of the remand proceeding cannot be predicted.

National Ambient Air Quality Standards

Environmental groups and 13 states filed a joint petition with the D.C. Court of Appeals arguing that the EPA's particulate matter rule does not adequately restrict levels of particulate matter, especially with respect to the annual and secondary standards. In 2009, the D.C. Court of Appeals remanded the annual and secondary standards to the EPA for further review and consideration. In November 2011, environmental groups petitioned the court to require the EPA to issue a proposal regarding reconsideration of the standards by February 15, 2012, and issue a final rule by September 15, 2012. On January 23, 2012, the EPA replied to the petition with a schedule that would require the agency to issue a proposed rule by June 2012 and a final rule by June 2013. The outcome of this matter cannot be predicted.

In 2008, the EPA revised the 8-hour primary and secondary standards for the NAAQS for ground-level ozone. Additional nonattainment areas may be designated in PEC's and PEF's service territories as a result of these revised standards. A number of states, environmental groups and industry associations filed petitions against the revised NAAQS in the D.C. Court of Appeals. The EPA requested the D.C. Court of Appeals to suspend proceedings in the case while the EPA evaluates whether to maintain, modify or otherwise reconsider the revised NAAQS. In 2009, the EPA announced that it was reconsidering the level of the ozone NAAQS and it will stay plans to designate nonattainment areas until after the reconsideration has been completed.

In 2010, the EPA announced a proposed revision to the primary ozone NAAQS. In addition, the EPA proposed a cumulative seasonal secondary standard. On September 2, 2011, President Obama announced that the EPA would withdraw the proposed revision. As a result, the ozone NAAQS promulgated in 2008 will be implemented, and the review of the standard has been deferred until 2013. With respect to the 2008 standard, all areas in our service territories are currently in compliance.

In 2010, the EPA announced a revision to the primary NAAQS for nitrogen dioxide (NO_2). Currently, there are no monitors reporting violation of this new standard in our service territories, but an expanded monitoring network will provide additional data, which could result in additional nonattainment areas. Additionally, the EPA revised the 1-hour NAAQS for SO_2 in 2010. Implementation of the new 1-hour NAAQS for SO_2 uses air quality modeling along with monitoring data in determining whether areas are attaining the new standard, which is likely to expand the number of nonattainment areas. No additional nonattainment areas have been designated to date in our service territories. Should additional nonattainment areas for the NAAQS for NO_2 and SO_2 be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of these matters cannot be predicted.

On July 13, 2011, the EPA made available its proposed action on the combined review of the secondary NAAQS for NOx and sulfur oxides (SOx) and expects to issue a final rule by March 2012. In this rulemaking, the EPA is proposing to retain the existing secondary standards for NO_2 and SO_2 and is also proposing a new set of secondary standards identical to the health-based primary standards it set in 2010. For NOx, the new standard would be 100 parts per billion averaged over one hour, measured as NO_2. For SOx, the new standard would be 75 parts per billion averaged over one hour, measured as SO_2. Should nonattainment areas for secondary NAAQS for NOx and SOx be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of these matters cannot be predicted.

WATER QUALITY

General

As a result of the operation of certain pollution control equipment required to address the air quality issues outlined previously, new sources of wastewater discharge will be generated at certain affected facilities. Integration of these new wastewater discharges into the existing wastewater treatment processes is currently ongoing and will result in permitting, construction and treatment requirements imposed on the Utilities now and into the future. The future costs of complying with these requirements could be material to our or the Utilities' results of operations or financial position.

In 2009, the EPA concluded after a multi-year study of power plant wastewater discharges that regulations have not kept pace with changes in the electric power industry since the regulations were issued in 1982, including addressing impacts to wastewater discharge from operation of air pollution control equipment. As a result, the EPA has announced that it plans to revise the regulations that govern wastewater discharge, which may result in operational changes and additional compliance costs in the future. The outcome of this matter cannot be predicted.

More stringent effluent limitations contained in the current water discharge permit for the Mayo Steam Electric Plant became effective in June 2011. PEC is currently negotiating the issuance of a special order by consent with the North Carolina Division of Water Quality, which would defer the agency's enforcement of the more stringent effluent limitations due to the plant's inability to achieve compliance with those limitations. The special order by consent, if issued, is expected to include the required development and installation of enhanced water pollution control technology and application of less stringent interim effluent limitations until PEC's planned project to bring the plant into compliance with the more stringent effluent limitations is completed. However, since the special order by consent has not yet been issued in final form, it is not possible to determine the extent of the planned project. Moreover, the special order by consent does not prevent actions by the EPA or third parties. Thus, the outcome of these matters cannot be determined.

On October 5, 2011, Earthjustice, on behalf of the Sierra Club and Florida Wildlife Federation, filed a petition seeking review of the water discharge permit issued to CR1, CR2 and CR3 (See Note 22D).

Section 316(b) of the Clean Water Act

Section 316(b) requires cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. The EPA promulgated a rule implementing Section 316(b) in respect to existing power plants in July 2004.

A number of states, environmental groups and others sought judicial review of the July 2004 rule. In 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding provisions of the rule to the EPA, and the EPA suspended the rule pending further rulemaking, with the exception of the requirement that permitted facilities must meet any requirements under Section 316(b) as determined by the permitting authorities on a case-by-case, best professional judgment basis. Following appeal, in 2009, the U.S. Supreme Court issued an opinion holding that the EPA, in selecting the "best technology" pursuant to Section 316(b), does have the authority to reject technology when its costs are "wholly disproportionate" to the benefits expected. Also, the U.S. Supreme Court held that EPA's site-specific variance procedure (contained in the July 2004 rule) was permissible in that the procedure required testing to determine whether costs would be "significantly greater than" the benefits before a variance would be considered. As a result of these developments, our plans and associated estimated costs to comply with Section 316(b) will need to be reassessed and determined in accordance with any revised or new implementing rule after it is established by the EPA. In December 2010, consent decrees were entered in two pending federal actions brought by environmental groups against the EPA requiring the EPA to issue proposed Section 316(b) rules by March 28, 2011, and to issue a final decision by July 27, 2012.

On April 20, 2011, the EPA published its proposed regulations for cooling water intake structures at existing power generating, manufacturing and industrial facilities that withdraw more than two million gallons of water per day from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. The proposed regulations would establish nationwide, uniform standards for impingement mortality (immobilization of aquatic organisms against an intake screen) and case-by-case, site-specific standards for entrainment mortality (lethal effects due to passage of aquatic organisms into a cooling system). Comments on the proposed rule have been timely submitted by affected parties, including PEC and PEF. The outcome of this matter cannot be predicted.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

State, federal and international attention to global climate change is expected to result in the regulation of CO_2 and other GHGs. While state-level study groups have been active in all three of our jurisdictions, we continue to believe that this issue requires a national policy framework – one that provides certainty and consistency. Our balanced solution as discussed in "Other Matters – Energy Demand" is a comprehensive plan to meet the anticipated demand in our service territories and provides a solid basis for slowing and reducing CO_2 emissions by focusing on energy efficiency, alternative and renewable energy and a state-of-the-art power system.

The EPA has begun the process of regulating GHG emissions through use of the CAA. In 2007, the U.S. Supreme Court ruled that the EPA has the authority under the CAA to regulate CO_2 emissions from new automobiles. According to the EPA this also results in stationary sources, such as coal-fired power plants, being subject to regulation of GHG emissions under the CAA. In 2009, the EPA announced that six GHGs (CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride) pose a threat to public health and welfare under the CAA. A number of parties have filed petitions for review of this finding in the D.C. Court of Appeals. The full impact of regulation under GHG initiatives and any final legislation, if enacted, cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time for which the Utilities would seek corresponding rate recovery. We are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue.

In 2010, the EPA announced a schedule for development of a new source performance standard for new and existing fossil fuel-fired electric utility units. Under the schedule, the EPA was to propose the standard by September 30, 2011, and issue the final rule by May 2012. The EPA is now expected to propose the standard in the first quarter of 2012.

The EPA issued the final "tailoring rule," which establishes the thresholds for applicability of the Prevention of Significant Deterioration program permitting requirements for GHG emissions from stationary sources such as power plants and manufacturing facilities. Prevention of Significant Deterioration is a construction air pollution permitting program designed to ensure air quality does not degrade beyond the NAAQS levels or beyond specified incremental amounts above a prescribed baseline level. The tailoring rule initially raises the permitting applicability threshold for GHG emissions to 75,000 tons per year. These developments require PEC and PEF to address GHG emissions in new air quality permits. The permitting requirements for GHG emissions from stationary sources began on January 2, 2011. A number of parties have filed petitions for review of the tailoring rule in the D.C. Court of Appeals. The impact of these developments cannot be predicted.

In 2009, the EPA issued the final GHG emissions reporting rule, which establishes a national protocol for the reporting of annual GHG emissions. Facilities that emit greater than 25,000 metric tons per year of GHGs must report annual emissions by March 31 of the following year. The reporting requirements began in 2011 with year 2010 emissions and we complied with the requirement of the reporting rule. Because the rule builds on current emission-reporting requirements, compliance with the requirements is not expected to have a material impact on the Utilities.

There are ongoing efforts to reach a new international climate change treaty to succeed the Kyoto Protocol. The Kyoto Protocol was originally adopted by the United Nations to address global climate change by reducing emissions of CO_2 and other GHGs. Although the treaty went into effect in 2005, the United States has not ratified it. In 2009, the United Nations Framework Convention on Climate Change convened the 15th Conference of the Parties to conduct further negotiations on GHG emissions reductions. At the conclusion of the conference, a number of the parties, including the United States, entered into a nonbinding accord calling upon the parties to submit emission reduction targets for 2020 to the United Nations Framework Convention on Climate Change Secretariat by the end of January 2010. In 2010, President Obama submitted a proposal to Congress to reduce the U.S. GHG emissions in the range of 17 percent below 2005 levels by 2020, subject to future congressional action. To date, Congress has not enacted legislation implementing the president's proposal.

Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol, potential new international treaties or federal or state proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time.

In May 2011, PEC and PEF were named, along with numerous other defendants, in a complaint of a class action lawsuit. Plaintiffs claim that defendants' GHG emissions contributed to the frequency and intensity of storms such as Hurricane Katrina. We cannot predict the outcome of this matter (See Note 22C).

REGULATORY ENVIRONMENT

The Utilities' operations in North Carolina, South Carolina and Florida are regulated by the NCUC, the SCPSC and the FPSC, respectively. The Utilities are also subject to regulation by the FERC, the NRC and other federal and state agencies common to the utility business. As a result of regulation, many of the fundamental business decisions, as well as the rate of return the Utilities are permitted the opportunity to earn, are subject to the approval of one or more of these governmental agencies.

To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give retail ratepayers the right to choose their electricity provider or otherwise restructure or deregulate the electric industry. We cannot anticipate if any of these states will move to increase retail competition in the electric industry.

Current retail rate matters affected by state regulatory authorities are discussed in Notes 8B and 8C. This discussion identifies specific retail rate matters, the status of the issues and the associated effects on our consolidated financial statements.

On April 28, 2010, we accepted a grant from the DOE for $200 million in federal matching infrastructure funds. In addition to providing the Utilities real-time information about the state of their electric grids, the smart grid transition will enable customers to better understand and manage their energy use, and will provide for more efficient integration of renewable energy resources. Supplementing the DOE grant, the Utilities will invest more than $300 million in smart grid projects, which include enhancements to distribution equipment, installation of 160,000 additional smart meters and additional public infrastructure for plug-in electric vehicles. Projects funded by the grant must be completed by April 2013.

Through December 31, 2011, we have incurred $225 million of allowable, 50 percent reimbursable, smart grid project costs, and have submitted to the DOE requests for reimbursement of $112 million, of which we have received $89 million.

Concerns about climate change and oil price volatility have led to proposed and enacted legislation at the federal and state levels to increase renewable energy and GHG emissions.

The NC REPS requires PEC to file an annual compliance report with the NCUC demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC REPS requirement via renewable energy certificates earned after January 1, 2008. North Carolina electric power suppliers with a renewable energy compliance obligation, including PEC, are participating in the renewable energy certificate tracking system, which came online July 1, 2010. North Carolina law mandates that utilities achieve a targeted amount of energy from specified renewable energy resources or implementation of energy-efficiency measures beginning with a 3 percent requirement in 2012 escalating to 12.5 percent in 2021. PEC expects to be in compliance with this requirement.

In 2007, the governor of Florida issued executive orders to address reduction of GHG emissions. The executive orders include adoption of a maximum allowable emissions level of GHGs for Florida utilities, which will require, at a minimum, the following three reduction milestones: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; and by 2050, emissions not greater than 20 percent of Year 1990 utility sector emissions. The executive orders also requested that the FPSC initiate a rulemaking that would (1) require Florida utilities to produce at least 20 percent of their electricity from renewable sources; (2) reduce the cost of connecting solar and other renewable energy technologies to Florida's power grid by adopting uniform statewide interconnection standards for all utilities; and (3) authorize a uniform, statewide method to enable residential and commercial customers who generate electricity from onsite renewable technologies of up to 1 MW in capacity to offset their consumption over a billing period by allowing their electric meters to turn backward when they generate electricity (net metering).

In response to the executive orders, Florida energy law enacted in 2008 includes provisions that required the FPSC to develop a renewable portfolio standard that the FPSC would present to the legislature for ratification and also includes provisions that direct the FDEP to develop rules establishing a cap-and-trade program to regulate GHG emissions that the FDEP would present to the legislature no earlier than January 2010 for ratification. To date, the Florida legislature has not ratified or enacted any renewable portfolio standard or cap-and-trade rules or programs. Until these agency actions are finalized, we cannot predict the outcome of this matter.

Our balanced solution, as described in "Energy Demand," demonstrates our commitment to environmental responsibility.

ENERGY DEMAND

Implementing state and federal energy policies, promoting environmental stewardship and providing reliable electricity to meet the anticipated long-term growth within the Utilities' service territories will require a balanced approach. The three main elements of this balanced solution are: (1) energy efficiency; (2) alternative and renewable energy; and (3) a state-of-the-art power system.

We are continuing the expansion and enhancement of our DSM and EE programs because energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. DSM programs include programs and initiatives that shift the timing of electricity use from peak to nonpeak periods, such as load management, electricity system and operating controls, direct load control, interruptible load, and electric system equipment and operating controls. Our previously discussed smart grid projects will aid in these initiatives. EE programs include any equipment, physical or program change that results in less energy used to perform the same function. We provide our residential customers with home energy audits and offer EE programs that provide incentives for customers to implement measures that reduce energy use. For business customers, we also provide energy audits and other tools, including an interactive Internet website with online calculators, programs and efficiency tips, to help them reduce their energy use.

We are actively engaged in a variety of alternative and renewable energy projects to pursue the generation of electricity from biomass, solar, hydrogen and landfill-gas technologies. Among our projects, we have executed contracts to purchase approximately 350 MW of electricity generated from biomass, including over 200 MW for compliance with NC REPS. The majority of these projects should be online within the next five years. In addition, we have executed purchased power agreements for approximately 30 MW of electricity generated from solar photovoltaic generation, with the majority purchased for compliance with NC REPS. Of the 30 MW of purchased solar photovoltaic generation, 12 MW are online and the remainder is expected to come online during 2012. Additionally, customers across our service territory have connected more than 11 MW of solar photovoltaic energy systems to our grid. Progress Energy offers a range of solar incentives and programs, which have increased, and will continue to significantly increase, our use of solar energy over the next decade.

We are pursuing numerous options to create a state-of-the-art power system, including investments in smart grid technology and advanced environmental controls on our coal-fired plants. In the coming years, we will continue to invest in existing nuclear plants and evaluate plans for building or co-owning new generating plants. Due to the anticipated long-term growth in our service territories, retirement of existing coal generation and potential changes in environmental regulations, we are constructing new natural gas-fueled generating facilities in the Carolinas and we estimate that we will require new generating facilities in both Florida and the Carolinas in the first half of the next decade. In addition to nuclear generation, we are evaluating natural gas-fired plants, renewable generation resources, energy-efficiency initiatives and economic purchased power to meet this increased need. At this time, no definitive decisions have been made to construct or when to construct our proposed new nuclear plants (See "Nuclear – Potential New Construction") or to acquire new generation from another utility's regional nuclear project. In the near term, we will focus our efforts on modernizing the power system and pursuing all elements of a balanced portfolio while looking to new nuclear capacity as a critical part of the long-term mix.

In 2009, PEC announced a coal-to-gas modernization strategy whereby the 11 remaining coal-fired generating facilities in North Carolina that do not have scrubbers would be retired prior to the end of their useful lives and their approximately 1,500 MW of generating capacity replaced with new natural gas-fueled facilities. The original strategy called for the retirement of the coal-fired units by the end of 2017; however, we currently expect the plants will be retired no later than the end of 2013. PEC has received approval from the NCUC for construction of an approximately 950-MW natural gas-fueled generating facility at a site in Wayne County, N.C., to be placed in service in January 2013. PEC has also received approval from the NCUC to construct an approximately 620-MW natural gas-fueled generating facility at a site in New Hanover County, N.C., to replace the existing coal-fired generation at this site. The facility is projected to be placed in service in December 2013. After 2013, PEC will continue to operate its Roxboro, Mayo and Asheville coal-fired plants in North Carolina, which have state-of-the-art emission controls. Emissions of NOx, SO_2, mercury and other pollutants have been reduced significantly at these sites.

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 take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved. Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs, uprates and certain other modifications.

In light of the events at the Fukushima Daiichi nuclear power station in Japan, the NRC formed a task force to conduct a comprehensive review of processes and regulations to determine whether the agency should make additional improvements to the nuclear regulatory system. On July 13, 2011, the task force proposed a set of improvements designed to ensure protection, enhance accident mitigation, strengthen emergency preparedness and improve efficiency of NRC programs. The NRC is also expected to issue a longer-term report with recommendations for the Commission's consideration by early 2012. With the ongoing investigations into the nature and extent of damages in Japan, the underlying causes of the situation and the lack of clarity around regulatory and political responses, we cannot predict to what extent the NRC will impose additional licensing and safety-related requirements. See Item 1A, "Risk Factors."

In September 2009, CR3 began an outage for normal refueling and maintenance, as well as its uprate project to increase its generating capacity and to replace two steam generators. During preparations to replace the steam generators, we discovered a delamination within the concrete of the outer wall of the containment structure, which has resulted in an extension of the outage. After a comprehensive analysis, we have determined that the concrete delamination at CR3 was caused by redistribution of stresses on the containment wall that occurred when we created an opening to accommodate the replacement of the unit's steam generators. In March 2011, engineers investigated and subsequently determined that a new delamination had occurred in another area of the structure after initial repair work was completed and during the late stages of retensioning the containment building. Subsequent to March 2011, monitoring equipment has detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations could occur during the repair process. Engineering design of the repair is under way. A number of factors could affect the repair plan, the return-to-service date and costs, including regulatory reviews, final engineering designs, contract negotiations, the ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis and other developments. (See Note 8C).

PEC's nuclear units have operating licenses granted by the NRC that have been renewed to 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On March 9, 2009, the NRC docketed, or accepted for review, PEF's application for a 20-year renewal on the operating license for CR3, which would extend the operating license through 2036, when approved. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will renew the license. The license renewal application for CR3 is currently under review by the NRC. The NRC's remaining open items in the license renewal review process are associated with the containment structure repair. Once the repair design has been completed and evaluated, the NRC may proceed with the renewal application review of the containment structure. Assuming the repair is successful, management believes CR3 will satisfy the requirements for the license renewal.

POTENTIAL NEW CONSTRUCTION

While we have not made a final determination on nuclear construction, we continue to take steps to keep open the option of building a plant or plants. During 2008, PEC and PEF filed COL applications to potentially construct new nuclear plants in North Carolina and Florida (See Item 1A, "Risk Factors"). The NRC estimated that it will take approximately three to four years to review and process the COL applications. We have focused on the potential nuclear plant construction in Florida given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions as well as existing state legislative policy that is supportive of nuclear projects.

In 2006, we announced that PEF selected Levy to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs. On July 30, 2008, PEF filed its COL application with the NRC for two reactors. PEF also completed and submitted a Limited Work Authorization request for Levy concurrent with the COL application. The FPSC issued the final order granting PEF's petition for the Determination of Need for Levy on August 12, 2008. On October 6, 2008, the NRC docketed the Levy nuclear project application. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL.

PEF's initial schedule anticipated performing certain site work pursuant to the Limited Work Authorization prior to COL receipt. However, in 2009, the NRC staff determined that certain schedule-critical work that PEF had proposed to perform within the scope of the Limited Work Authorization will not be authorized until the NRC issues the COL. Consequently, excavation and foundation preparation work will be shifted until after COL issuance, which is expected in 2013 if the current licensing schedule remains on track. This factor alone resulted in a minimum 20-month schedule shift later than the originally anticipated timeframe. Since then, regulatory and economic conditions have changed, resulting in additional schedule shifts. These conditions include the permitting and licensing process, national and state economic conditions, short-term natural gas prices and other FPSC decisions. Uncertainty regarding PEF's access to capital on reasonable terms, PEF's ability to secure joint owners and increasing uncertainty surrounding carbon regulation and its costs could be other factors to affect the Levy schedule.

PEF signed the EPC agreement on December 31, 2008, with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two Westinghouse AP1000 nuclear units to be constructed at Levy. More than half of the approximate $7.650 billion contract price is fixed or firm with agreed upon escalation factors. The EPC agreement includes various incentives, warranties, performance guarantees, liquidated damage provisions and parent guarantees designed to incent the contractor to perform efficiently. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. We executed an amendment to the EPC agreement in 2010 due to the schedule shifts previously discussed. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF completed vendor negotiations in July 2011 to continue or suspend purchase orders for long lead time equipment without material fees or charges.

The total escalated cost for the two generating units was estimated in PEF's petition for the Determination of Need for Levy to be approximately $14 billion. This total cost estimate included land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. An additional $3 billion was estimated for the necessary transmission equipment and approximately 200 miles of transmission lines associated with the project. PEF's 2011 nuclear cost-recovery filing included an updated analysis that demonstrated continued feasibility of the Levy project with PEF's current estimated range of total escalated cost, including transmission, of $17.2 billion to $22.5 billion. The filed estimated cost range primarily reflects cost escalation resulting from the schedule shifts. Many factors will affect the total cost of the project and once PEF receives the COL, it will further refine the project timeline and budget. As previously discussed, we continue to evaluate the Levy project on an ongoing basis.

In 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC's application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris. On April 17, 2008, the NRC docketed the Harris application. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, a new plant would not be online until the middle of the next decade (See "Energy Demand" above).

SPENT NUCLEAR FUEL MATTERS

The Nuclear Waste Policy Act of 1982 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 Policy Act of 1982 promotes increased usage of interim storage of spent nuclear fuel at existing nuclear plants. We will continue to maximize the use of spent fuel storage capability within our own facilities for as long as feasible.

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

See Note 22D for discussion of the status of the Utilities' contracts with the DOE for spent nuclear fuel storage.

SYNTHETIC FUELS TAX CREDITS

Historically, we had substantial operations associated with the production and sale of coal-based solid synthetic fuels, which qualified for federal income tax credits so long as certain requirements were satisfied. Tax credits generated under the synthetic fuels tax credit program (including those generated by Florida Progress prior to our acquisition) were $1.891 billion, of which $1.026 billion has been used through December 31, 2011, to offset regular federal income tax liability and $865 million is being carried forward as deferred tax credits that do not expire.

See Note 22D and Item 1A, "Risk Factors," for additional discussion related to our previous synthetic fuels operations and the associated tax credits generated under the synthetic fuels tax credit program.

LEGAL

We are subject to federal, state and local legislation and court orders. The specific issues, the status of the issues, accruals associated with issue resolutions and our associated exposures are discussed in detail in Note 22D.

NEW ACCOUNTING STANDARDS

See Note 3 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 MD&A, insofar as they relate to PEC: "Results of Operations," "Application of Critical Accounting Policies and Estimates," "Liquidity and Capital Resources" and "Other Matters."

The following MD&A 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 "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors," for a discussion of the factors that may impact any such forward-looking statements made herein.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

PEC has primarily used a combination of debt securities, commercial paper and its revolving credit agreement for liquidity needs in excess of cash provided by operations. PEC also participates in the utility money pool, which allows PEC and PEF to lend and borrow to and from each other and borrow from, but not lend to, the Parent.

See discussion of credit ratings in Progress Energy "Credit Rating Matters."

PEC expects to have sufficient resources to meet its future obligations through a combination of cash from operations, availability under its credit facility, money pool borrowings, issuances of commercial paper and long-term debt and/or contributions of equity from the Parent.

CASH FLOW DISCUSSION

HISTORICAL FOR 2011 AS COMPARED TO 2010 AND 2010 AS COMPARED TO 2009

Cash Flows from Operations

Net cash provided by operating activities decreased $381 million for 2011, when compared to 2010. The decrease was primarily due to $269 million higher cash used for inventory, a $122 million increase in pension plan funding, the $107 million less favorable impact of weather as previously discussed and $33 million paid for interest rate hedges terminated in conjunction with the issuance of long-term debt in 2011, partially offset by $205 million in lower net cash for taxes. The increase in cash used for inventory was primarily due to higher coal purchases in 2011 reflecting anticipated winter consumption and inventory levels that remained high at year-end (due to lower natural gas prices) combined with higher 2010 consumption of existing inventory levels to meet system requirements resulting from favorable weather.

Net cash provided by operating activities increased $235 million in 2010, when compared to 2009. The increase was primarily due to the $115 million favorable impact of weather partially offset by $78 million higher nuclear plant outage and maintenance costs included in O&M, both as previously discussed; $141 million lower cash used for inventory, primarily due to higher coal consumption as a result of favorable weather in 2010 that was fulfilled through the 2010 usage of inventory from year-end 2009; $86 million lower cash used for pension and other benefits primarily due to a reduction of contributions made in 2010; and $37 million lower cash paid for income taxes. These amounts were partially offset by a $108 million decrease in the over-recovery of fuel as a result of higher fuel costs in 2010.

Investing Activities

Net cash used by investing activities increased $239 million in 2011, when compared with 2010. The increase was primarily due to a $200 million change in advances to affiliated companies.

Net cash used by investing activities increased $67 million in 2010, when compared with 2009. The increase was primarily due to a $359 million increase in gross property additions and a $61 million increase in nuclear fuel additions, partially offset by a $351 million decrease in advances to affiliated companies. The increase in property additions is primarily due to increased capital expenditures at the Wayne County, New Hanover County and Harris generating facilities. The increase in nuclear fuel additions was primarily due to the three nuclear refueling and maintenance outages in 2010, compared to two in 2009.

Financing Activities

Net cash provided by financing activities increased $215 million for 2011, when compared to 2010. The increase was primarily due to the $500 million issuance of first mortgage bonds in 2011 and $185 million in commercial paper borrowings in 2011, partially offset by the $585 million payment of dividends to the Parent in 2011 compared to $100 million in 2010.

Net cash used by financing activities decreased $10 million for 2010, when compared to 2009. The decrease was primarily due to the $400 million payment at maturity of long-term debt in 2009, the $110 million net repayment of commercial paper in 2009 and a $100 million reduction in dividends paid to the Parent in 2010 compared to 2009. These impacts were partially offset by $600 million issuance of first mortgage bonds in 2009.

On September 15, 2011, PEC issued $500 million 3.00% First Mortgage Bonds due September 15, 2021. A portion of the net proceeds was used to repay outstanding short-term debt and the remainder was used for general corporate purposes, including construction expenditures.

On October 15, 2010, PEC entered into a new $750 million, three-year RCA with a syndication of 22 financial institutions. The RCA is used to provide liquidity support for PEC's issuances of commercial paper and other short-term obligations, and for general corporate purposes. The RCA will expire on October 15, 2013. The prior $450 million RCA was terminated effective October 15, 2010 (See "Credit Facilities and Registration Statements").

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

On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.

SHORT-TERM DEBT

At December 31, 2011, PEC had an outstanding short-term debt balance consisting primarily of commercial paper borrowing totaling $219 million at a weighted average interest rate of 0.51%.

At the end of each month during the three months ended December 31, 2011, PEC had a maximum short-term debt balance of $219 million and an average short-term debt balance of $73 million at a weighted average interest rate of 0.51%. PEC's short-term debt during the three months ended December 31, 2011, consisted primarily of commercial paper and money pool borrowings.

At the end of each month during the year ended December 31, 2011, PEC had a maximum short-term debt balance of $219 million and an average short-term debt balance of $83 million at a weighted average interest rate of 0.39%. PEC's short-term debt during the year ended December 31, 2011, consisted primarily of commercial paper and money pool borrowings.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEC's estimated capital requirements for 2012, 2013 and 2014 are approximately $1.4 billion, $1.3 billion and $1.4 billion, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation and upgrade existing facilities as discussed in Progress Energy "Capital Expenditures."

PEC expects to fund its capital requirements primarily through a combination of cash from operations, issuance of long-term debt and/or contributions of equity from the Parent. In addition, PEC has a $750 million credit facility that supports 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.

At December 31, 2011, the current portion of PEC's long-term debt was $500 million. We expect to fund the $500 million of First Mortgage Bonds, due July 15, 2012, with a combination of cash from operations, commercial paper borrowings and/or long-term debt.

Over the long term, meeting the anticipated load growth will require a balanced approach, including energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities, including new generating facilities in the Carolinas currently under construction and the potential for additional new baseload generating facilities toward the middle of the next decade. This approach will require PEC to make significant capital investments. See Progress Energy "Introduction – Strategy" for additional information. PEC may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

PEC typically files a shelf registration statement with the SEC under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock. We expect to file a new shelf registration statement with the SEC, as PEC's previously filed shelf registration statement for these securities expired November 17, 2011. (See "Credit Facilities and Registration Statements.")

CAPITALIZATION RATIOS

The following table shows each component of capitalization as a percentage of total capitalization at December 31, 2011 and 2010. In addition to total equity and preferred stock, total capitalization includes the following in total debt: long-term debt, net, current portion of long-term debt and capital lease obligations.

	2011	2010
Total equity	**53.2%**	57.9%
Preferred stock	**0.6%**	0.7%
Total debt	**46.2%**	41.4%

See the discussion of PEC's future liquidity and capital resources, including financial market impacts, under Progress Energy and see Note 12 for further information regarding PEC's debt and credit facility.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

See discussion under Progress Energy and Notes 22A, 22B and 22C for information on PEC's off-balance sheet arrangements and contractual obligations at December 31, 2011.

GUARANTEES

See discussion under Progress Energy and Note 22C for a discussion of PEC's guarantees.

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 18 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. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented in the following table are estimates and therefore will likely differ from actual purchase amounts. 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 PEC's contractual cash obligations and other commercial commitments at December 31, 2011, 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 (See Note 12)[(a)]	$ 4,199	$ 500	$ 405	$ 700	$ 2,594
Interest payments on long-term debt[(b)]	1,794	193	301	235	1,065
Capital lease obligations (See Note 22B)	18	2	10	-	6
Operating leases (See Note 22B)[(c)]	764	29	96	97	542
Fuel and purchased power (See Note 22A)[(d)]	6,838	1,252	1,864	1,482	2,240
Other purchase obligations (See Note 22A)	913	354	230	87	242
Minimum pension funding requirements[(e)]	183	61	93	29	-
Other postretirement benefits[(f)]	244	19	43	48	134
Uncertain tax positions[(g)]	-	-	-	-	-
Other commitments[(h)]	78	13	26	26	13
Total	$ 15,031	$ 2,423	$ 3,068	$ 2,704	$ 6,836

(a) PEC's maturing debt obligations are generally expected to be repaid with cash from operations or refinanced with new debt issuances in the capital markets.

(b) Interest payments on long-term debt are based on the interest rate effective at December 31, 2011.

(c) Amounts include certain related executory cost commitments.

(d) Essentially all of PEC's fuel and certain purchased power costs are eligible for recovery through cost-recovery clauses in accordance with state and federal regulations and therefore do not require separate liquidity support. Amounts exclude precedent and conditional contracts of $1.510 billion. (See Note 22A.)

(e) Represents the projected minimum required contributions to the qualified pension trust for a total of 10 years. These amounts are subject to change significantly based on factors such as pension asset earnings and market interest rates.

(f) Represents projected benefit payments for a total of 10 years related to PEC's postretirement health and life plans and are subject to change based on factors such as experienced claims and general health care cost trends.

(g) Uncertain tax positions of $73 million are not reflected in this table as PEC cannot predict when open income tax years will be closed with completed examinations. PEC is not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2012.

(h) By NCUC order, in 2008, PEC began transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of the original $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

PEF

The information required by this item is incorporated herein by reference to the following portions of Progress Energy's MD&A, insofar as they relate to PEF: "Results of Operations," "Application of Critical Accounting Policies and Estimates," "Liquidity and Capital Resources" and "Other Matters."

The following MD&A 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 "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors," for a discussion of the factors that may impact any such forward-looking statements made herein.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

PEF has primarily used a combination of debt securities, equity contributions from the Parent, commercial paper and its revolving credit agreement for liquidity needs in excess of cash provided by operations. PEF also participates in the utility money pool, which allows PEC and PEF to lend and borrow to and from each other and borrow from, but not lend to, the Parent.

See discussion of credit ratings in Progress Energy "Credit Rating Matters."

PEF expects to have sufficient resources to meet its future obligations through a combination of cash from operations, availability under its credit facility, money pool borrowings, issuances of commercial paper and long-term debt and/or contributions of equity from the Parent.

CASH FLOW DISCUSSION

HISTORICAL FOR 2011 AS COMPARED TO 2010 AND 2010 AS COMPARED TO 2009

Cash Flows from Operations

Net cash provided by operating activities decreased $439 million for 2011, when compared to 2010. The decrease was primarily due to $161 million lower recovery of capacity costs, the $112 million less favorable impact of weather as previously discussed, a $78 million increase in pension plan funding, $72 million decrease in NEIL reimbursements for CR3 replacement power costs and $33 million paid for interest rate hedges terminated in conjunction with the issuance of long-term debt in 2011. The change in recovery of capacity costs in 2011 was primarily due to the $51 million refund of prior-year over-recovery of capacity costs and the 2010 collection of $110 million of previously under-recovered capacity costs.

Net cash provided by operating activities increased $67 million in 2010, when compared with 2009. The increase was primarily due to the $88 million favorable impact of weather as previously discussed; $98 million net cash receipts from income taxes in 2010 compared to $184 million of net cash payments for income taxes in 2009; and $56 million lower cash used for inventory, primarily due to higher coal consumption in 2010 as a result of favorable weather that was fulfilled through 2010 usage of inventory from year-end 2009. These amounts were partially offset by an $81 million under-recovery of fuel in 2010 compared to a $103 million over-recovery of fuel in 2009 driven by lower fuel rates in 2010 and $6 million of net payments of cash collateral to counterparties on derivative contracts in 2010 compared to $190 million net refunds of cash collateral in 2009.

Investing Activities

Net cash used by investing activities decreased $280 million in 2011, when compared with 2010. The decrease was primarily due to a $198 million decrease in gross property additions, primarily due to lower spending for environmental compliance and nuclear projects; $27 million of litigation judgment proceeds; and $24 million increase in receipt of smart grid grant reimbursement.

Net cash used by investing activities decreased $541 million in 2010, when compared with 2009. The decrease was primarily due to a $435 million decrease in gross property additions and a $64 million increase in cash provided by insurance proceeds. The decrease in property additions was driven by decreases in environmental compliance spending and expenditures for nuclear projects. The increase in cash provided by insurance proceeds is driven by the receipt of NEIL insurance proceeds for repairs due to the CR3 extended outage.

Financing Activities

Net cash used by financing activities increased $306 million for 2011, when compared to 2010. The increase was primarily due to the combined $600 million issuance of first mortgage bonds in March 2010 and the $460 million increase in payment of dividends to the Parent in 2011, partially offset by a $300 million issuance of first mortgage bonds in August 2011, $233 million of commercial paper borrowings in 2011 and the $211 million change in advances from affiliated companies.

Net cash provided by financing activities decreased $374 million for 2010, when compared to 2009. The decrease was primarily due to a $620 million contribution from the Parent in 2009, a $361 million decrease in advances from affiliates and a $300 million retirement at maturity of long-term debt in 2010. The decreases are partially offset by the $600 million issuance of first mortgage bonds in 2010 and $371 million repayment of commercial paper in 2009.

On July 15, 2011, PEF paid at maturity $300 million of its 6.65% First Mortgage Bonds with proceeds from short-term debt borrowings.

On August 18, 2011, PEF issued $300 million 3.10% First Mortgage Bonds due August 15, 2021. The net proceeds were used to repay a portion of outstanding short-term debt, of which $300 million was issued to repay PEF's July 15, 2011 maturity.

On March 25, 2010, PEF issued $250 million of 4.55% First Mortgage Bonds due 2020 and $350 million of 5.65% First Mortgage Bonds due 2040. Proceeds were used to repay the outstanding balance of PEF's notes payable to affiliated companies, to repay the maturity of PEF's $300 million 4.50% First Mortgage Bonds due June 1, 2010, and for general corporate purposes.

On October 15, 2010, PEF entered into a new $750 million, three-year RCA with a syndication of 22 financial institutions. The RCA is used to provide liquidity support for PEF's issuances of commercial paper and other short-term obligations, and for general corporate purposes. The RCA will expire on October 15, 2013. The prior $450 million RCA was terminated effective October 15, 2010 (See "Credit Facilities and Registration Statements").

In 2009, PEF did not issue or retire long-term debt.

SHORT-TERM DEBT

At December 31, 2011, PEF had outstanding short-term debt consisting primarily of commercial paper borrowings totaling $241 million at an interest rate of 0.51 percent.

At the end of each month during the three months ended December 31, 2011, PEF had a maximum short-term debt balance of $249 million and an average short-term debt balance of $179 million at a weighted average interest rate of 0.46 percent. PEF's short-term debt during the three months ended December 31, 2011, included only commercial paper and money pool borrowings.

At the end of each month during the year ended December 31, 2011, PEF had a maximum short-term debt balance of $350 million and an average short-term debt balance of $106 million at a weighted average interest rate of 0.40 percent. PEF's short-term debt during the year ended December 31, 2011, included only commercial paper and money pool borrowings.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEF's estimated capital requirements for 2012, 2013 and 2014 are approximately \$720 million to \$820 million, \$830 million to \$930 million, and \$760 million, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation and upgrade existing facilities, as discussed in Progress Energy "Capital Expenditures." PEF's estimated capital requirements for 2012 and 2013 include potential nuclear construction expenditures, primarily related to PEF's Levy project. Because of announced schedule shifts, we negotiated an amendment to the Levy EPC agreement (See discussion under "Other Matters – Nuclear – Potential New Construction"). The forecasted capital expenditures reflect the announced schedule shift. Project spending for 2014 and beyond will be determined once the timing for the receipt of the COL is known and more detailed estimates have been developed based on this and other factors. Future nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages of joint ownership. These expenditures are subject to cost-recovery provisions in PEF's jurisdiction (See Note 8C).

PEF's estimated capital expenditures exclude estimates for the repair of the CR3 containment building and the completion of the extended power uprate project. Estimates of these projects will be developed upon the completion of ongoing engineering and project planning, the resolution of negotiations with NEIL regarding insurance coverage of the second CR3 delamination, and final decisions regarding repair versus retirement.

PEF expects to fund its capital requirements primarily through a combination of cash from operations, issuance of long-term debt and/or contributions of equity from the Parent. In addition, PEF has a \$750 million credit facility that supports the issuance of commercial paper. Access to the commercial paper market and the utility money pool provide additional liquidity to help meet PEF's working capital requirements.

Over the long term, meeting the anticipated load growth will require a balanced approach, including energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities, potentially including new baseload generating facilities in Florida toward the middle of the next decade. This approach will require PEF to make significant capital investments. PEF may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

PEF typically files a shelf registration statement with the SEC under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock. We expect to file a new shelf registration statement with the SEC, as PEF's previously filed shelf registration statement for these securities expired November 17, 2011 (See "Credit Facilities and Registration Statements").

CAPITALIZATION RATIOS

The following table shows each component of capitalization as a percentage of total capitalization at December 31, 2011 and 2010. In addition to total equity and preferred stock, total capitalization includes the following in total debt: long-term debt, net, current portion of long-term debt, notes payable to affiliated companies and capital lease obligations.

	2011	2010
Total common stock equity	**48.5%**	50.9%
Preferred stock	**0.4%**	0.3%
Total debt	**51.1%**	48.8%

See the discussion of PEF's future liquidity and capital resources, including financial market impacts, under Progress Energy and see Note 12 for further information regarding PEF's debt and credit facility.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

See discussion under Progress Energy and Notes 22A, 22B and 22C for information on PEF's off-balance sheet arrangements and contractual obligations at December 31, 2011.

MARKET RISK AND DERIVATIVES

Under its risk management policy, PEF 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

This information called for by Item 7 is omitted for PEF pursuant to Instruction I(2)(a) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various risks related to changes in market conditions. Market risk represents the potential loss arising from adverse changes in market rates and prices. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk to the extent that the counterparty fails to perform under the contract. We minimize such risk by performing credit and financial reviews using a combination of financial analysis and publicly available credit ratings of such counterparties (See Note 18). Both PEC and PEF also have limited counterparty exposure for commodity hedges (primarily gas and oil hedges) by spreading concentration risk over a number of counterparties.

The following disclosures about market risk 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 Item 1A, "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.

Certain market risks are inherent in our financial instruments, which arise from transactions entered into in the normal course of business. Our primary exposures are changes in interest rates with respect to our long-term debt and commercial paper, fluctuations in the return on marketable securities with respect to our NDT funds, changes in the market value of CVOs and changes in energy-related commodity prices.

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 our operations, such as purchase and sales commitments and inventory.

PROGRESS ENERGY

INTEREST RATE RISK

As part of our debt portfolio management and daily cash management, we have variable rate long-term debt and may have commercial paper and/or loans outstanding under our RCA facilities, which are also exposed to floating interest rates. Approximately 11 percent and 7 percent of consolidated debt had variable rates at December 31, 2011 and 2010, respectively.

Based on our variable rate long-term and short-term debt balances at December 31, 2011, a 100 basis point change in interest rates would result in an annual pre-tax interest expense change of approximately $15 million. We had $671 million of outstanding short-term debt at December 31, 2011.

From time to time, we use interest rate derivative instruments to adjust the mix between fixed and floating rate debt in our debt portfolio, to mitigate our exposure to interest rate fluctuations associated with certain debt instruments and to hedge interest rates with regard to future fixed-rate debt issuances.

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 exposure in the transaction is the cost of replacing the agreements at current market rates.

We use a number of models and methods to determine interest rate risk exposure and fair value of derivative positions. For reporting purposes, fair values and exposures of derivative positions are determined as of the end of the reporting period using the Bloomberg Financial Markets system.

In accordance with GAAP, interest rate derivatives that qualify as hedges are separated into one of two categories: cash flow hedges or fair value hedges. Cash flow hedges are used to reduce exposure to changes in cash flow due to fluctuating interest rates. Fair value hedges are used to reduce exposure to changes in fair value due to interest rate changes.

The following tables provide information, at December 31, 2011 and 2010, about our 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 Parent-obligated mandatorily redeemable preferred securities of trust. The tables also include estimates of the fair value of our interest rate risk-sensitive instruments based on quoted market prices for these or similar issues. For interest rate forward contracts, the tables present notional amounts and weighted-average interest rates by contractual mandatory termination dates for 2012 to 2016 and thereafter and the related fair value. Notional amounts are used to calculate the settlement amounts under the interest rate forward contracts. See Note 18 for more information on interest rate derivatives.

December 31, 2011								**Fair Value**
								December 31,
(dollars in millions)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**	**2011**
Fixed-rate long-term debt	**$ 950**	**$ 830**	**$ 300**	**$ 1,000**	**$ 300**	**$ 8,449**	**$ 11,829**	**$ 14,128**
Average interest rate	**6.67%**	**4.96%**	**6.05%**	**5.18%**	**5.63%**	**5.80%**	**5.76%**	
Variable-rate long-term debt	**-**	**-**	**-**	**-**	**-**	**$ 861**	**$ 861**	**$ 861**
Average interest rate	**-**	**-**	**-**	**-**	**-**	**0.30%**	**0.30%**	
Debt to affiliated trust[(a)]	**-**	**-**	**-**	**-**	**-**	**$ 309**	**$ 309**	**$ 318**
Interest rate	**-**	**-**	**-**	**-**	**-**	**7.10%**	**7.10%**	
Interest rate forward contracts[(b)]	**$ 400**	**$ 100**	**$ -**	**-**	**-**	**-**	**$ 500**	**$ (93)**
Average pay rate	**4.23%**	**4.37%**	**-**	**-**	**-**	**-**	**4.26%**	
Average receive rate	**[(c)]**	**[(c)]**	**-**	**-**	**-**	**-**	**[(c)]**	

(a) Florida Progress Funding Corporation - Junior Subordinated Deferrable Interest Notes.

(b) Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.

(c) Rate is 3-month London Inter Bank Offered Rate (LIBOR), which was 0.58% at December 31, 2011.

At December 31, 2011, Progress Energy had $500 million notional of open forward starting swaps, including $250 million notional at PEC and $50 million notional at PEF.

December 31, 2010								Fair Value
								December 31,
(dollars in millions)	2011	2012	2013	2014	2015	Thereafter	Total	2010
Fixed-rate long-term debt	$ 1,000	$ 950	$ 830	$ 300	$ 1,000	$ 7,449	$ 11,529	$ 12,826
Average interest rate	6.96%	6.67%	4.96%	6.05%	5.18%	6.18%	6.11%	
Variable-rate long-term debt	-	-	-	-	-	$ 861	$ 861	$ 861
Average interest rate	-	-	-	-	-	0.53%	0.53%	
Debt to affiliated trust[(a)]	-	-	-	-	-	$ 309	$ 309	$ 315
Interest rate	-	-	-	-	-	7.10%	7.10%	
Interest rate forward contracts[(b)]	$ 550	$ 400	$ 100	-	-	-	$ 1,050	$ (35)
Average pay rate	4.19%	4.23%	4.37%	-	-	-	4.22%	
Average receive rate	[(c)]	[(c)]	[(c)]	-	-	-	[(c)]	

(a) Florida Progress Funding Corporation - Junior Subordinated Deferrable Interest Notes.
(b) Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.
(c) Rate is 3-month LIBOR, which was 0.30% at December 31, 2010.

At December 31, 2010, Progress Energy had $1.050 billion notional of open forward starting swaps, including $350 million notional at PEC and $200 million notional at PEF.

MARKETABLE SECURITIES PRICE RISK

The Utilities 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. At December 31, 2011 and December 31, 2010, the fair value of these funds was $1.647 billion and $1.571 billion, respectively, including $1.088 billion and $1.017 billion, respectively, for PEC and $559 million and $554 million, respectively, for PEF. We actively monitor our portfolio by benchmarking the performance of our 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 Utilities' 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 earnings. See Note 14 for further information on the trust fund securities.

CONTINGENT VALUE OBLIGATIONS MARKET VALUE RISK

CVOs are recorded at fair value, and gains and losses from changes in fair value are recognized in earnings. The 18.5 million outstanding CVOs not held by Progress Energy at December 31, 2011, had a fair value of $14 million. The 98.6 million CVOs outstanding at December 31, 2010, had a fair value of $15 million. We perform sensitivity analyses to estimate our exposure to the market risk of the CVOs. The sensitivity analyses performed on the CVOs use observable prices obtained from brokers or quote services to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. A hypothetical 10 percent increase in the December 31, 2011 market price would result in a $1 million increase in the fair value of the CVOs and a corresponding increase in the CVO liability.

COMMODITY PRICE RISK

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 our ownership of energy-related assets. Our exposure to these fluctuations is significantly limited by the cost-based regulation of the Utilities. 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, most of our long-term power sales contracts shift substantially all fuel price risk to the purchaser.

Most of our physical commodity contracts are not derivatives or qualify as normal purchases or sales. Therefore, such contracts are not recorded at fair value. At December 31, 2011, substantially all derivative commodity instrument positions were subject to retail regulatory treatment.

See Note 18 for additional information with regard to our commodity contracts and use of economic and cash flow derivative financial instruments.

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, fluctuations in the return on marketable securities with respect to its NDT funds and changes in energy-related commodity prices.

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

INTEREST RATE RISK

The following tables provide information at December 31, 2011 and 2010, about PEC's interest rate risk-sensitive instruments:

December 31, 2011								**Fair Value December 31,**
(dollars in millions)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**	**2011**
Fixed-rate long-term debt	**$ 500**	**$ 405**	**$ -**	**$ 700**	**$ -**	**$ 1,974**	**$ 3,579**	**$ 4,102**
Average interest rate	**6.50%**	**5.14%**	**-**	**5.21%**	**-**	**5.18%**	**5.36%**	
Variable-rate long-term debt	**-**	**-**	**-**	**-**	**-**	**$ 620**	**$ 620**	**$ 620**
Average interest rate	**-**	**-**	**-**	**-**	**-**	**0.20%**	**0.20%**	
Interest rate forward contracts[(a)]	**$ 200**	**$ 50**	**-**	**-**	**-**	**-**	**$ 250**	**$ (46)**
Average pay rate	**4.27%**	**4.43%**	**-**	**-**	**-**	**-**	**4.30%**	
Average receive rate	**(b)**	**(b)**		**-**	**-**	**-**	**(b)**	

(a) Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.
(b) Rate is 3-month LIBOR, which was 0.58% at December 31, 2011.

At December 31, 2011, PEC had $250 million notional of open forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

December 31, 2010								Fair Value December 31,
(dollars in millions)	2011	2012	2013	2014	2015	Thereafter	Total	2010
Fixed-rate long-term debt	$ -	$ 500	$ 405	$ -	$ 700	$ 1,474	$ 3,079	$ 3,413
Average interest rate	-	6.50%	5.14%	-	5.21%	5.91%	5.75%	
Variable-rate long-term debt	-	-	-	-	-	$ 620	$ 620	$ 620
Average interest rate	-	-	-	-	-	0.54%	0.54%	
Interest rate forward contracts[(a)]	$ 100	$ 200	$ 50	-	-	-	$ 350	$ (8)
Average pay rate	4.31%	4.27%	4.43%	-	-	-	4.30%	
Average receive rate	(b)	(b)	(b)	-	-	-	(b)	

(a) Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.
(b) Rate is 3-month LIBOR, which was 0.30% at December 31, 2010.

At December 31, 2010, PEC had $350 million notional of open forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

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 the 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. See "Commodity Price Risk" discussion under Progress Energy mentioned previously and Note 18 for additional information with regard to PEC's commodity contracts and use of derivative financial instruments.

PEF

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

The information required by this item is incorporated herein by reference to Progress Energy's Quantitative and Qualitative Disclosures About Market Risk insofar as it relates to PEF.

INTEREST RATE RISK

The following tables provide information at December 31, 2011 and 2010, about PEF's interest rate risk-sensitive instruments:

December 31, 2011 (dollars in millions)	2012	2013	2014	2015	2016	Thereafter	Total	Fair Value December 31, 2011
Fixed-rate long-term debt	$ -	$ 425	$ -	$ 300	$ -	$ 3,525	$ 4,250	$ 5,193
Average interest rate	-	4.80%	-	5.10%	-	5.74%	5.60%	
Variable-rate long-term debt	-	-	-	-	-	$ 241	$ 241	$ 241
Average interest rate	-	-	-	-	-	0.57%	0.57%	
Interest rate forward contracts[a]	-	$ 50	$ -	-	-	-	$ 50	$ (9)
Average pay rate	-	4.30%	-	-	-	-	4.30%	
Average receive rate		[b]		-	-	-	[b]	

[a] Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.
[b] Rate is 3-month LIBOR, which was 0.58% at December 31, 2011.

At December 31, 2011, PEF had $50 million notional of open forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

December 31, 2010 (dollars in millions)	2011	2012	2013	2014	2015	Thereafter	Total	Fair Value December 31, 2010
Fixed-rate long-term debt	$ 300	$ -	$ 425	$ -	$ 300	$ 3,225	$ 4,250	$ 4,730
Average interest rate	6.65%	-	4.80%	-	5.10%	5.99%	5.85%	
Variable-rate long-term debt	-	-	-	-	-	$ 241	$ 241	$ 241
Average interest rate	-	-	-	-	-	0.52%	0.52%	
Interest rate forward contracts[a]	$ 150	-	$ 50	-	-	-	$ 200	$ (7)
Average pay rate	4.18%	-	4.30%	-	-	-	4.21%	
Average receive rate	[b]	-	-[b]	-	-	-	[b]	

(a) Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.
(b) Rate is 3-month LIBOR, which was 0.30% at December 31, 2010.

At December 31, 2010, PEF had $200 million notional of open forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

COMMODITY PRICE RISK

PEF 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. PEF's exposure to these fluctuations is significantly limited by its cost-based regulation. The FPSC allows PEF to recover certain fuel and purchased power costs to the extent the FPSC 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. See "Commodity Price Risk" discussion under Progress Energy mentioned previously and Note 18 for additional information with regard to PEF's commodity contracts and use of derivative financial instruments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

Each of the preceding combined notes to the financial statements of the Progress Registrants are applicable to Progress Energy, Inc. but not to each of PEC and PEF. The following table sets forth which notes are applicable to each of PEC and PEF.

Registrant	**Applicable Notes**
PEC	1 through 3, 5 through 8, 10 through 15, 17 through 19, 21, 22, and 24
PEF	1 through 3, 5 through 8, 10 through 15, 17 through 19, 21, 22, and 24

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 subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, changes in total equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 Progress Energy, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, 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 February 28, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2012

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of INCOME

(in millions except per share data)

Years ended December 31	**2011**	2010	2009
Operating revenues	$ **8,907**	$ 10,190	$ 9,885
Operating expenses			
Fuel used in electric generation	**2,893**	3,300	3,752
Purchased power	**1,093**	1,279	911
Operation and maintenance	**2,036**	2,027	1,894
Depreciation, amortization and accretion	**701**	920	986
Taxes other than on income	**562**	580	557
Other	**34**	30	13
Total operating expenses	**7,319**	8,136	8,113
Operating income	**1,588**	2,054	1,772
Other income (expense)			
Interest income	**2**	7	14
Allowance for equity funds used during construction	**103**	92	124
Other, net	**(58)**	-	6
Total other income, net	**47**	99	144
Interest charges			
Interest charges	**760**	779	718
Allowance for borrowed funds used during construction	**(35)**	(32)	(39)
Total interest charges, net	**725**	747	679
Income from continuing operations before income tax	**910**	1,406	1,237
Income tax expense	**323**	539	397
Income from continuing operations	**587**	867	840
Discontinued operations, net of tax	**(5)**	(4)	(79)
Net income	**582**	863	761
Net income attributable to noncontrolling interests, net of tax	**(7)**	(7)	(4)
Net income attributable to controlling interests	$ **575**	$ 856	$ 757
Average common shares outstanding – basic	**296**	291	279
Basic and diluted earnings per common share			
Income from continuing operations attributable to controlling interests, net of tax	$ **1.96**	$ 2.96	$ 2.99
Discontinued operations attributable to controlling interests, net of tax	**(0.02)**	(0.01)	(0.28)
Net income attributable to controlling interests	$ **1.94**	$ 2.95	$ 2.71
Dividends declared per common share	$ **2.119**	$ 2.480	$ 2.480
Amounts attributable to controlling interests			
Income from continuing operations, net of tax	$ **580**	$ 860	$ 836
Discontinued operations, net of tax	**(5)**	(4)	(79)
Net income attributable to controlling interests	$ **575**	$ 856	$ 757

See Notes to Progress Energy, Inc. Consolidated Financial Statements.

PROGRESS ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

(in millions)	December 31, 2011	December 31, 2010
ASSETS		
Utility plant		
Utility plant in service	$ 31,065	$ 29,708
Accumulated depreciation	(12,001)	(11,567)
Utility plant in service, net	19,064	18,141
Other utility plant, net	217	220
Construction work in progress	2,449	2,205
Nuclear fuel, net of amortization	767	674
Total utility plant, net	22,497	21,240
Current assets		
Cash and cash equivalents	230	611
Receivables, net	889	1,033
Inventory	1,438	1,226
Regulatory assets	275	176
Derivative collateral posted	147	164
Deferred tax assets	371	156
Prepayments and other current assets	133	110
Total current assets	3,483	3,476
Deferred debits and other assets		
Regulatory assets	3,025	2,374
Nuclear decommissioning trust funds	1,647	1,571
Miscellaneous other property and investments	407	413
Goodwill	3,655	3,655
Other assets and deferred debits	345	325
Total deferred debits and other assets	9,079	8,338
Total assets	$ 35,059	$ 33,054
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 295 million and 293 million shares issued and outstanding, respectively	$ 7,434	$ 7,343
Accumulated other comprehensive loss	(165)	(125)
Retained earnings	2,752	2,805
Total common stock equity	10,021	10,023
Noncontrolling interests	4	4
Total equity	10,025	10,027
Preferred stock of subsidiaries	93	93
Long-term debt, affiliate	273	273
Long-term debt, net	11,718	11,864
Total capitalization	22,109	22,257
Current liabilities		
Current portion of long-term debt	950	505
Short-term debt	671	-
Accounts payable	909	994
Interest accrued	200	216
Dividends declared	78	184
Customer deposits	340	324
Derivative liabilities	436	259
Accrued compensation and other benefits	195	175
Other current liabilities	306	298
Total current liabilities	4,085	2,955
Deferred credits and other liabilities		
Noncurrent income tax liabilities	2,355	1,696
Accumulated deferred investment tax credits	103	110
Regulatory liabilities	2,700	2,635
Asset retirement obligations	1,265	1,200
Accrued pension and other benefits	1,625	1,514
Derivative liabilities	352	278
Other liabilities and deferred credits	465	409
Total deferred credits and other liabilities	8,865	7,842
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$ 35,059	$ 33,054

See Notes to Progress Energy, Inc. Consolidated Financial Statements.

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions)

Years ended December 31		**2011**		2010		2009
Operating activities						
Net income	**$**	**582**	$	863	$	761
Adjustments to reconcile net income to net cash provided by operating activities						
Depreciation, amortization and accretion		**870**		1,083		1,135
Deferred income taxes and investment tax credits, net		**353**		478		220
Deferred fuel (credit) cost		**(102)**		(2)		290
Allowance for equity funds used during construction		**(103)**		(92)		(124)
Amount to be refunded to customers (Note 8C)		**288**		-		-
Pension, postretirement and other employee benefits		**180**		198		135
Other adjustments to net income		**50**		49		136
Cash provided (used) by changes in operating assets and liabilities						
Receivables		**175**		(200)		26
Inventory		**(210)**		98		(99)
Derivative collateral posted		**20**		(23)		200
Other assets		**(23)**		(1)		14
Income taxes, net		**51**		90		(14)
Accounts payable		**(69)**		125		(26)
Accrued pension and other benefits		**(396)**		(164)		(285)
Other liabilities		**(51)**		35		(98)
Net cash provided by operating activities		**1,615**		2,537		2,271
Investing activities						
Gross property additions		**(2,066)**		(2,221)		(2,295)
Nuclear fuel additions		**(226)**		(221)		(200)
Purchases of available-for-sale securities and other investments		**(5,017)**		(7,009)		(2,350)
Proceeds from available-for-sale securities and other investments		**4,970**		6,990		2,314
Insurance proceeds		**79**		64		-
Other investing activities		**48**		(3)		(1)
Net cash used by investing activities		**(2,212)**		(2,400)		(2,532)
Financing activities						
Issuance of common stock, net		**53**		434		623
Dividends paid on common stock		**(734)**		(717)		(693)
Payments of short-term debt with original maturities greater than 90 days		**-**		-		(629)
Net increase (decrease) in short-term debt		**667**		(140)		(381)
Proceeds from issuance of long-term debt, net		**1,286**		591		2,278
Retirement of long-term debt		**(1,000)**		(400)		(400)
Other financing activities		**(56)**		(19)		8
Net cash provided (used) by financing activities		**216**		(251)		806
Net (decrease) increase in cash and cash equivalents		**(381)**		(114)		545
Cash and cash equivalents at beginning of year		**611**		725		180
Cash and cash equivalents at end of year	**$**	**230**	$	611	$	725
Supplemental disclosures						
Cash paid for interest less amount capitalized, net	**$**	**793**	$	709	$	701
Cash (received) paid for income taxes		**(78)**		(56)		87
Significant noncash transactions						
Accrued property additions		**334**		313		252
Asset retirement obligation additions and estimate revisions		**(4)**		(36)		(384)

See Notes to Progress Energy, Inc. Consolidated Financial Statements.

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of CHANGES in TOTAL EQUITY

(in millions except per share data)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Noncontrolling Interests	Total Equity
Balance, December 31, 2008	**264**	**$6,206**	**$ (25)**	**$ (116)**	**$ 2,622**	**$ 6**	**$ 8,693**
Net income[(a)]		-	-	-	757	-	757
Other comprehensive income		-	-	29	-	-	29
Issuance of shares	17	623	-	-	-	-	623
Allocation of ESOP shares		8	13	-	-	-	21
Stock-based compensation expense		36	-	-	-	-	36
Dividends ($2.480 per share)		-	-	-	(704)	-	(704)
Distributions to noncontrolling interests		-	-	-	-	(1)	(1)
Other		-	-	-	-	1	1
Balance, December 31, 2009	**281**	**6,873**	**(12)**	**(87)**	**2,675**	**6**	**9,455**
Cumulative effect of change in accounting principle		-	-	-	-	(2)	(2)
Net income[(a)]		-	-	-	856	3	859
Other comprehensive loss		-	-	(38)	-	-	(38)
Issuance of shares	12	434	-	-	-	-	434
Allocation of ESOP shares		9	12	-	-	-	21
Stock-based compensation expense		27	-	-	-	-	27
Dividends ($2.480 per share)		-	-	-	(726)	-	(726)
Distributions to noncontrolling interests		-	-	-	-	(2)	(2)
Other		-	-	-	-	(1)	(1)
Balance, December 31, 2010	**293**	**7,343**	**-**	**(125)**	**2,805**	**4**	**10,027**
Net income[(a)]		**-**	**-**	**-**	**575**	**3**	**578**
Other comprehensive loss		**-**	**-**	**(40)**	**-**	**-**	**(40)**
Issuance of shares	**2**	**53**	**-**	**-**	**-**	**-**	**53**
Stock-based compensation expense		**38**	**-**	**-**	**-**	**-**	**38**
Dividends ($2.119 per share)		**-**	**-**	**-**	**(628)**	**-**	**(628)**
Distributions to noncontrolling interests		**-**	**-**	**-**	**-**	**(3)**	**(3)**
Balance, December 31, 2011	**295**	**$ 7,434**	**$ -**	**$ (165)**	**$ 2,752**	**$ 4**	**$ 10,025**

[(a)] For the year ended December 31, 2011, consolidated net income of $582 million includes $4 million attributable to preferred shareholders of subsidiaries. For the year ended December 31, 2010, consolidated net income of $863 million includes $4 million attributable to preferred shareholders of subsidiaries. For the year ended December 31, 2009, consolidated net income of $761 million includes $4 million attributable to preferred shareholders of subsidiaries. Income attributable to preferred shareholders of subsidiaries is not a component of total equity and is excluded from the table above.

See Notes to Progress Energy, Inc. Consolidated Financial Statements

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31,	**2011**	2010	2009
Net income	**$ 582**	$ 863	$ 761
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax expense of $5, $4 and $4)	**8**	6	6
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $3, $2 and $3)	**5**	3	4
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $56, $22 and $(10))	**(87)**	(34)	16
Net unrecognized items for pension and other postretirement benefits (net of tax (expense) benefit of $(24), $8 and $(1))	**34**	(13)	2
Other (net of tax benefit of $-)	**-**	-	1
Other comprehensive (loss) income	**(40)**	(38)	29
Comprehensive income	**542**	825	790
Comprehensive income attributable to noncontrolling interests, net of tax	**(7)**	(7)	(4)
Comprehensive income attributable to controlling interests	**$ 535**	$ 818	$ 786

See Notes to Progress Energy, Inc. Consolidated Financial Statements.

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 subsidiaries ("PEC") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, changes in total equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of PEC's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of 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 Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, 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
February 28, 2012

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

CONSOLIDATED STATEMENTS of INCOME

(in millions) Years ended December 31	**2011**	2010	2009
Operating revenues	**$ 4,528**	$ 4,922	$ 4,627
Operating expenses			
Fuel used in electric generation	**1,387**	1,686	1,680
Purchased power	**315**	302	229
Operation and maintenance	**1,182**	1,158	1,072
Depreciation, amortization and accretion	**514**	479	470
Taxes other than on income	**211**	218	210
Other	**34**	8	-
Total operating expenses	**3,643**	3,851	3,661
Operating income	**885**	1,071	966
Other income (expense)			
Interest income	**1**	3	5
Allowance for equity funds used during construction	**71**	64	33
Other, net	**(1)**	-	(18)
Total other income, net	**71**	67	20
Interest charges			
Interest charges	**205**	205	207
Allowance for borrowed funds used during construction	**(21)**	(19)	(12)
Total interest charges, net	**184**	186	195
Income before income tax	**772**	952	791
Income tax expense	**256**	350	277
Net income	**516**	602	514
Net loss attributable to noncontrolling interests, net of tax	**-**	1	2
Net income attributable to controlling interests	**516**	603	516
Preferred stock dividend requirement	**(3)**	(3)	(3)
Net income available to parent	**$ 513**	$ 600	$ 513

See Notes to Progress Energy Carolinas, Inc. Consolidated Financial Statements.

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED BALANCE SHEETS

(in millions)	December 31, 2011	December 31, 2010
ASSETS		
Utility plant		
Utility plant in service	**$ 17,439**	$ 16,388
Accumulated depreciation	**(7,567)**	(7,324)
Utility plant in service, net	**9,872**	9,064
Other utility plant, net	**181**	184
Construction work in progress	**1,294**	1,233
Nuclear fuel, net of amortization	**540**	480
Total utility plant, net	**11,887**	10,961
Current assets		
Cash and cash equivalents	**20**	230
Receivables, net	**492**	519
Receivables from affiliated companies	**13**	44
Inventory	**775**	590
Deferred fuel cost	**31**	71
Income taxes receivable	**8**	90
Deferred tax assets	**142**	65
Prepayments and other current assets	**68**	47
Total current assets	**1,549**	1,656
Deferred debits and other assets		
Regulatory assets	**1,310**	987
Nuclear decommissioning trust funds	**1,088**	1,017
Miscellaneous other property and investments	**188**	183
Other assets and deferred debits	**80**	95
Total deferred debits and other assets	**2,666**	2,282
Total assets	**$ 16,102**	$ 14,899
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 200 million shares authorized, 160 million shares issued and outstanding	**$ 2,148**	$ 2,130
Accumulated other comprehensive loss	**(71)**	(33)
Retained earnings	**3,011**	3,083
Total common stock equity	**5,088**	5,180
Preferred stock	**59**	59
Long-term debt, net	**3,693**	3,693
Total capitalization	**8,840**	8,932
Current liabilities		
Current portion of long-term debt	**500**	-
Short-term debt	**188**	-
Notes payable to affiliated companies	**31**	-
Accounts payable	**527**	534
Payables to affiliated companies	**41**	109
Interest accrued	**77**	74
Customer deposits	**116**	106
Derivative liabilities	**130**	53
Accrued compensation and other benefits	**110**	99
Other current liabilities	**85**	81
Total current liabilities	**1,805**	1,056
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**1,976**	1,608
Accumulated deferred investment tax credits	**98**	104
Regulatory liabilities	**1,543**	1,461
Asset retirement obligations	**896**	849
Accrued pension and other benefits	**687**	723
Other liabilities and deferred credits	**257**	166
Total deferred credits and other liabilities	**5,457**	4,911
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$ 16,102**	$ 14,899

See Notes to Progress Energy Carolinas, Inc. 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	**2011**	2010	2009
Operating activities			
Net income	**$ 516**	$ 602	$ 514
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	**659**	602	585
Deferred income taxes and investment tax credits, net	**262**	285	64
Deferred fuel cost	**43**	79	187
Allowance for equity funds used during construction	**(71)**	(64)	(33)
Pension, postretirement and other employee benefits	**67**	78	65
Other adjustments to net income	**(50)**	4	67
Cash provided (used) by changes in operating assets and liabilities			
Receivables	**106**	(76)	42
Receivables from affiliated companies	**31**	(11)	(4)
Inventory	**(184)**	85	(56)
Other assets	**(16)**	(24)	28
Income taxes, net	**92**	(54)	50
Accounts payable	**(26)**	51	(18)
Payables to affiliated companies	**(68)**	37	(10)
Accrued pension and other benefits	**(247)**	(95)	(181)
Other liabilities	**23**	19	(17)
Net cash provided by operating activities	**1,137**	1,518	1,283
Investing activities			
Gross property additions	**(1,232)**	(1,198)	(839)
Nuclear fuel additions	**(211)**	(183)	(122)
Purchases of available-for-sale securities and other investments	**(571)**	(489)	(696)
Proceeds from available-for-sale securities and other investments	**515**	437	642
Changes in advances to affiliated companies	**2**	202	(149)
Other investing activities	**28**	1	1
Net cash used by investing activities	**(1,469)**	(1,230)	(1,163)
Financing activities			
Dividends paid on preferred stock	**(3)**	(3)	(3)
Dividends paid to parent	**(585)**	(100)	(200)
Net increase (decrease) in short-term debt	**185**	-	(110)
Proceeds from issuance of long-term debt, net	**495**	-	595
Retirement of long-term debt	**-**	-	(400)
Changes in advances from affiliated companies	**31**	-	-
Contributions from parent	**-**	14	15
Other financing activities	**(1)**	(4)	-
Net cash provided (used) by financing activities	**122**	(93)	(103)
Net (decrease) increase in cash and cash equivalents	**(210)**	195	17
Cash and cash equivalents at beginning of year	**230**	35	18
Cash and cash equivalents at end of year	**$ 20**	$ 230	$ 35
Supplemental disclosures			
Cash paid for interest less amount capitalized, net	**$ 199**	$ 166	$ 171
Cash (received) paid for income taxes, net	**(97)**	108	144
Significant noncash transactions			
Accrued property additions	**236**	198	91
Asset retirement obligation additions and estimate revisions	**(4)**	1	(386)

See Notes to Progress Energy Carolinas, Inc. Consolidated Financial Statements.

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED STATEMENTS of CHANGES in TOTAL EQUITY

(in millions)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned ESOP Common Stock	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Noncontrolling Interests	Total Equity
Balance, December 31, 2008	**160**	**$ 2,083**	**$ (25)**	**$ (35)**	**$ 2,278**	**$ 4**	**$ 4,305**
Net income		-	-	-	516	(2)	514
Other comprehensive income		-	-	8	-	-	8
Allocation of ESOP shares		10	13	-	-	-	23
Stock-based compensation expense		15	-	-	-	-	15
Dividends paid to parent		-	-	-	(200)	-	(200)
Preferred stock dividends at stated rates		-	-	-	(3)	-	(3)
Tax dividend		-	-	-	(3)	-	(3)
Other		-	-	-	-	1	1
Balance, December 31, 2009	**160**	**2,108**	**(12)**	**(27)**	**2,588**	**3**	**4,660**
Cumulative effect of change in accounting principle		-	-	-	-	(2)	(2)
Net income		-	-	-	603	(1)	602
Other comprehensive loss		-	-	(6)	-	-	(6)
Allocation of ESOP shares		10	12	-	-	-	22
Stock-based compensation expense		12	-	-	-	-	12
Dividends paid to parent		-	-	-	(100)	-	(100)
Preferred stock dividends at stated rates		-	-	-	(3)	-	(3)
Tax dividend		-	-	-	(5)	-	(5)
Balance, December 31, 2010	**160**	**2,130**	**-**	**(33)**	**3,083**	**-**	**5,180**
Net income		**-**	**-**	**-**	**516**	**-**	**516**
Other comprehensive loss		**-**	**-**	**(38)**	**-**	**-**	**(38)**
Stock-based compensation expense		**18**	**-**	**-**	**-**	**-**	**18**
Dividends paid to parent		**-**	**-**	**-**	**(585)**	**-**	**(585)**
Preferred stock dividends at stated rates		**-**	**-**	**-**	**(3)**	**-**	**(3)**
Balance, December 31, 2011	**160**	**$ 2,148**	**$ -**	**$ (71)**	**$ 3,011**	**$ -**	**$ 5,088**

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31,	**2011**	2010	2009
Net income	**$ 516**	$ 602	$ 514
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax expense of $3, $3 and $2)	**5**	4	3
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $28, $6 and $(3))	**(43)**	(10)	5
Other comprehensive (loss) income	**(38)**	(6)	8
Comprehensive income	**478**	596	522
Comprehensive loss attributable to noncontrolling interests, net of tax	**-**	1	2
Comprehensive income attributable to controlling interests	**$ 478**	$ 597	$ 524

See Notes to Progress Energy Carolinas, Inc. Consolidated Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.:

We have audited the accompanying balance sheets of Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF") as of December 31, 2011 and 2010, and the related 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, 2011. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of PEF's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. PEF is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of PEF's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Florida Power Corporation d/b/a Progress Energy Florida, Inc. as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, 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
February 28, 2012

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

STATEMENTS of INCOME

(in millions)

Years ended December 31	**2011**	2010	2009
Operating revenues	**$ 4,369**	$ 5,254	$ 5,251
Operating expenses			
Fuel used in electric generation	**1,506**	1,614	2,072
Purchased power	**778**	977	682
Operation and maintenance	**881**	912	839
Depreciation, amortization and accretion	**169**	426	502
Taxes other than on income	**350**	362	347
Other	**(13)**	4	7
Total operating expenses	**3,671**	4,295	4,449
Operating income	**698**	959	802
Other income (expense)			
Interest income	**1**	1	4
Allowance for equity funds used during construction	**32**	28	91
Other, net	**2**	(1)	5
Total other income, net	**35**	28	100
Interest charges			
Interest charges	**253**	271	258
Allowance for borrowed funds used during construction	**(14)**	(13)	(27)
Total interest charges, net	**239**	258	231
Income before income tax	**494**	729	671
Income tax expense	**180**	276	209
Net income	**314**	453	462
Preferred stock dividend requirement	**(2)**	(2)	(2)
Net income available to parent	**$ 312**	$ 451	$ 460

See Notes to Progress Energy Florida, Inc. Financial Statements.

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

BALANCE SHEETS

(in millions)	December 31, 2011	December 31, 2010
ASSETS		
Utility plant		
Utility plant in service	**$ 13,461**	$ 13,155
Accumulated depreciation	**(4,356)**	(4,168)
Utility plant in service, net	**9,105**	8,987
Held for future use	**36**	36
Construction work in progress	**1,155**	972
Nuclear fuel, net of amortization	**227**	194
Total utility plant, net	**10,523**	10,189
Current assets		
Cash and cash equivalents	**16**	249
Receivables, net	**372**	496
Receivables from affiliated companies	**19**	11
Inventory	**663**	636
Regulatory assets	**244**	105
Derivative collateral posted	**123**	140
Deferred tax assets	**138**	77
Prepayments and other current assets	**39**	29
Total current assets	**1,614**	1,743
Deferred debits and other assets		
Regulatory assets	**1,602**	1,387
Nuclear decommissioning trust funds	**559**	554
Miscellaneous other property and investments	**42**	43
Other assets and deferred debits	**144**	140
Total deferred debits and other assets	**2,347**	2,124
Total assets	**$ 14,484**	$ 14,056
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 60 million shares authorized, 100 shares issued and outstanding	**$ 1,757**	$ 1,750
Accumulated other comprehensive loss	**(27)**	(4)
Retained earnings	**2,945**	3,144
Total common stock equity	**4,675**	4,890
Preferred stock	**34**	34
Long-term debt, net	**4,482**	4,182
Total capitalization	**9,191**	9,106
Current liabilities		
Current portion of long-term debt	**-**	300
Short-term debt	**233**	-
Notes payable to affiliated companies	**8**	9
Accounts payable	**358**	439
Payables to affiliated companies	**25**	60
Interest accrued	**54**	83
Customer deposits	**224**	218
Derivative liabilities	**268**	188
Accrued compensation and other benefits	**53**	47
Other current liabilities	**112**	121
Total current liabilities	**1,335**	1,465
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**1,405**	1,065
Regulatory liabilities	**1,071**	1,084
Asset retirement obligations	**369**	351
Accrued pension and other benefits	**598**	522
Capital lease obligations	**189**	199
Derivative liabilities	**231**	190
Other liabilities and deferred credits	**95**	74
Total deferred credits and other liabilities	**3,958**	3,485
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$ 14,484**	$ 14,056

See Notes to Progress Energy Florida, Inc. Financial Statements.

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

STATEMENTS of CASH FLOWS

(in millions)			
Years ended December 31	**2011**	2010	2009
Operating activities			
Net income	**$ 314**	$ 453	$ 462
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	**174**	446	527
Deferred income taxes and investment tax credits, net	**234**	324	64
Deferred fuel (credit) cost	**(145)**	(81)	103
Allowance for equity funds used during construction	**(32)**	(28)	(91)
Amount to be refunded to customers (Note 8C)	**288**	-	-
Pension, postretirement and other employee benefits	**62**	79	28
Other adjustments to net income	**26**	44	88
Cash provided (used) by changes in operating assets and liabilities			
Receivables	**78**	(110)	(15)
Receivables from affiliated companies	**(8)**	(3)	7
Inventory	**(26)**	13	(43)
Derivative collateral posted	**19**	(6)	190
Other assets	**(4)**	(17)	15
Income taxes, net	**51**	50	(75)
Accounts payable	**(46)**	79	(11)
Payables to affiliated companies	**(35)**	(2)	7
Accrued pension and other benefits	**(137)**	(61)	(83)
Other liabilities	**(48)**	24	(36)
Net cash provided by operating activities	**765**	1,204	1,137
Investing activities			
Gross property additions	**(816)**	(1,014)	(1,449)
Nuclear fuel additions	**(15)**	(38)	(78)
Purchases of available-for-sale securities and other investments	**(4,435)**	(6,386)	(1,540)
Proceeds from available-for-sale securities and other investments	**4,438**	6,390	1,545
Insurance proceeds	**76**	64	-
Other investing activities	**45**	(3)	(6)
Net cash used by investing activities	**(707)**	(987)	(1,528)
Financing activities			
Dividends paid on preferred stock	**(2)**	(2)	(2)
Dividends paid to parent	**(510)**	(50)	-
Net increase (decrease) in short-term debt	**233**	-	(371)
Proceeds from issuance of long-term debt, net	**296**	591	-
Retirement of long-term debt	**(300)**	(300)	-
Changes in advances from affiliated companies	**(1)**	(212)	149
Contributions from parent	**-**	-	620
Other financing activities	**(7)**	(12)	(7)
Net cash (used) provided by financing activities	**(291)**	15	389
Net (decrease) increase in cash and cash equivalents	**(233)**	232	(2)
Cash and cash equivalents at beginning of year	**249**	17	19
Cash and cash equivalents at end of year	**$ 16**	$ 249	$ 17
Supplemental disclosures			
Cash paid for interest less amount capitalized, net	**$ 287**	$ 241	$ 228
Cash (received) paid for income taxes	**(83)**	(98)	184
Significant noncash transactions			
Accrued property additions	**93**	111	156

See Notes to Progress Energy Florida, Inc. Financial Statements.

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

STATEMENTS of CHANGES in COMMON STOCK EQUITY

	Common Stock Outstanding		Accumulated Other Comprehensive		Total Common Stock
(in millions except shares outstanding)	Shares	Amount	(Loss) Income	Retained Earnings	Equity
Balance, December 31, 2008	**100**	**$ 1,116**	**$ (1)**	**$ 2,284**	**$ 3,399**
Net income		-	-	462	462
Other comprehensive income		-	4	-	4
Stock-based compensation expense		8	-	-	8
Contributions from parent		620	-	-	620
Preferred stock dividends at stated rates		-	-	(2)	(2)
Tax dividend		-	-	(1)	(1)
Balance, December 31, 2009	**100**	**1,744**	**3**	**2,743**	**4,490**
Net income		-	-	453	453
Other comprehensive loss		-	(7)	-	(7)
Stock-based compensation expense		6	-	-	6
Dividends paid to parent		-	-	(50)	(50)
Preferred stock dividends at stated rates		-	-	(2)	(2)
Balance, December 31, 2010	**100**	**1,750**	**(4)**	**3,144**	**4,890**
Net income		**-**	**-**	**314**	**314**
Other comprehensive loss		**-**	**(23)**	**-**	**(23)**
Stock-based compensation expense		**7**	**-**	**-**	**7**
Dividends paid to parent		**-**	**-**	**(510)**	**(510)**
Preferred stock dividends at stated rates		**-**	**-**	**(2)**	**(2)**
Tax dividend		**-**	**-**	**(1)**	**(1)**
Balance, December 31, 2011	**100**	**$ 1,757**	**$ (27)**	**$ 2,945**	**$ 4,675**

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

STATEMENTS of COMPREHENSIVE INCOME

(in millions)			
Years ended December 31,	**2011**	2010	2009
Net income	**$ 314**	$ 453	$ 462
Other comprehensive (loss) income			
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $15, $4 and $(2))	**(23)**	(7)	4
Other comprehensive (loss) income	**(23)**	(7)	4
Comprehensive income	**$ 291**	$ 446	$ 466

See Notes to Progress Energy Florida, Inc. Financial Statements.

COMBINED NOTES TO FINANCIAL STATEMENTS

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. ORGANIZATION

PROGRESS ENERGY

The Parent is a holding company headquartered in Raleigh, N.C., subject to regulation by the Federal Energy Regulatory Commission (FERC).

Our reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity. The Corporate and Other segment primarily includes amounts applicable to the activities of the Parent and Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable business segment. See Note 20 for further information about our segments.

PEC

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

PEF

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

B. BASIS OF PRESENTATION

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP), including GAAP for regulated operations. The financial statements include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy, and, as such, their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements. Intercompany balances and transactions have been eliminated in consolidation.

Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in noncontrolling interests in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for noncontrolling interests are reported on a net of tax basis if the underlying subsidiary is structured as a taxable entity.

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

Our presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under GAAP.

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

Certain amounts for 2010 and 2009 have been reclassified to conform to the 2011 presentation.

C. CONSOLIDATION OF VARIABLE INTEREST ENTITIES

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities (VIEs) for which we are the primary beneficiary. We determine whether we are the primary beneficiary of a VIE through a qualitative analysis that identifies which variable interest holder has the controlling financial interest in the VIE. The variable interest holder who has both of the following has the controlling financial interest and is the primary beneficiary: (1) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (2) the obligation to absorb losses of, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. In performing our analysis, we consider all relevant facts and circumstances, including: the design and activities of the VIE, the terms of the contracts the VIE has entered into, the nature of the VIE's variable interests issued and how they were negotiated with or marketed to potential investors, and which parties participated significantly in the design or redesign of the entity.

PROGRESS ENERGY

Progress Energy, through its subsidiary PEC, is the primary beneficiary of, and consolidates an entity that qualifies for rehabilitation tax credits under Section 47 of the Internal Revenue Code. Our variable interests are debt and equity investments in the VIE. There were no changes to our assessment of the primary beneficiary for this VIE during 2009 through 2011. No financial or other support has been provided to the VIE during the periods presented.

The following table sets forth the carrying amount and classification of our investment in the VIE as reflected in the Consolidated Balance Sheets at December 31:

(in millions)	**2011**	2010
Miscellaneous other property and investments	**$ 12**	$ 12
Cash and cash equivalents	**1**	-
Prepayments and other current assets	**-**	1
Accounts payable	**-**	5

The assets of the VIE are collateral for, and can only be used to settle, its obligations. The creditors of the VIE do not have recourse to our general credit or the general credit of PEC, and there are no other arrangements that could expose us to losses.

Progress Energy, through its subsidiary PEC, is the primary beneficiary of two VIEs that were established to lease buildings to PEC under capital lease agreements. Our maximum exposure to loss from these leases is a $7.5 million mandatory fixed price purchase option for one of the buildings. Total lease payments to these counterparties under the lease agreements were $2 million annually in 2011, 2010 and 2009. We have requested the necessary information to consolidate these entities; both entities from which the necessary financial information was requested declined to provide the information to us, and, accordingly, we have applied the information scope exception provided by GAAP to the entities. We believe the effect of consolidating the entities would have an insignificant impact on our common stock equity, net earnings or cash flows. However, because we have not received any financial information from the counterparties, the impact cannot be determined at this time.

PEC

See discussion of PEC's variable interests in VIEs within the Progress Energy section.

PEF

PEF has no significant variable interests in VIEs.

D. SIGNIFICANT ACCOUNTING POLICIES

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

We recognize revenue when it is realized or realizable and earned when all of the following criteria are met: persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; our price to the buyer is fixed or determinable; and collectability is reasonably assured. We recognize electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utility base revenues earned when service has been delivered but not billed by the end of the accounting period. The amount of unbilled revenues can vary significantly from period to period as a result of numerous factors, including seasonality, weather, customer usage patterns and customer mix. Customer prepayments are recorded as deferred revenue and recognized as revenues as the services are provided.

Periodically, we are permitted to start charging customers for proposed rate increases prior to receiving final approval from our regulatory authorities. Such amounts charged are subject to refund upon issuance of the final rate order. In addition, we may be required to refund amounts to customers for previously recognized revenues, through approved orders or settlement agreements, which are not related to proposed rate increases. We recognize revenue subject to refund when it is earned, and separately establish a reserve for amounts that could be refunded when it is probable that revenue will be refunded to customers. See Note 8C for discussion of revenue to be refunded in connection with the 2012 settlement agreement.

FUEL COST DEFERRALS

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

EXCISE TAXES

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for sales and use tax on a net basis and gross receipts tax, franchise taxes and other excise taxes on a gross basis.

The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income in the statements of income for the years ended December 31 were as follows:

(in millions)	**2011**	2010	2009
Progress Energy	**$ 315**	$ 345	$ 333
PEC	**110**	119	108
PEF	**205**	226	225

RELATED PARTY TRANSACTIONS

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

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs of units of property as well as indirect construction costs. 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 generally occur every two years. Maintenance activities under long-term service agreements with third parties are capitalized or expensed as appropriate as if the Utilities had performed the activities. Generally, the cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. For generating facilities to be retired or abandoned significantly before the end of their useful lives, the net carrying value is reclassified from plant in service, net to other utility plant, net when it becomes probable they will be retired or abandoned. When such facilities are removed from service, the remaining net carrying value is then reclassified to regulatory assets in accordance with the expected ratemaking treatment. Removal or disposal costs that do not represent asset retirement obligations (AROs) are charged to a regulatory liability.

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

Nuclear fuel is classified as a fixed asset and included in the utility plant section of the Consolidated Balance Sheets. Nuclear fuel in the front-end fuel processing phase is considered work in progress and not amortized until placed in service.

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

Substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 5A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization rates of utility assets (See Note 8).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method and included within fuel used in electric generation in the Consolidated Statements of Income.

FEDERAL GRANT

The American Recovery and Reinvestment Act, signed into law in February 2009, contains provisions promoting energy efficiency (EE) and renewable energy. On April 28, 2010, we accepted a grant from the United States Department of Energy (DOE) for $200 million in federal matching infrastructure funds in support of our smart grid initiatives. PEC and PEF each will receive up to $100 million over a three-year period as project work progresses. The DOE will provide reimbursement for 50 percent of allowable project costs, as incurred, up to the DOE's maximum obligation of $200 million. Projects funded by the grant must be completed by April 2013.

In accounting for the federal grant, we have elected to reduce the cost basis of select smart grid projects. As the select capital projects are placed into service, this will reduce depreciation expense over the life of the assets. Reimbursements by the DOE are deferred as a short-term or long-term liability on the Consolidated Balance Sheets based on their expected date of application to the select projects. Reimbursements related to capital projects are included in other investing activities in the Statement of Cash Flows when cash is received.

ASSET RETIREMENT OBLIGATIONS

AROs are legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability. Accretion expense is included in depreciation, amortization and accretion in the Consolidated Statements of Income. AROs have no impact on the income of the Utilities as the effects are offset by the establishment of regulatory assets and regulatory liabilities in order to reflect the ratemaking treatment of the related costs.

CASH AND CASH EQUIVALENTS

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

RECEIVABLES, NET

We record accounts receivable at net realizable value. This value includes an allowance for estimated uncollectible accounts to reflect any loss anticipated on the accounts receivable balances. The allowance for uncollectible accounts reflects our estimate of probable losses inherent in the accounts receivable, unbilled revenue, and other receivables balances. We calculate this allowance based on our history of write-offs, level of past due accounts, prior rate of recovery experience and relationships with and economic status of our customers.

INVENTORY

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

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to GAAP for regulated operations, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, the Utilities record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 8A). Management continually assesses whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Additionally, management continually assesses whether any regulatory liabilities have been incurred. The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

NUCLEAR COST DEFERRALS

PEF accounts for costs incurred in connection with the proposed nuclear expansion in Florida in accordance with FPSC regulations, which establish an alternative cost-recovery mechanism. PEF is allowed to accelerate the recovery of prudently incurred siting, preconstruction costs, AFUDC and incremental operation and maintenance expenses resulting from the siting, licensing, design and construction of a nuclear plant through PEF's capacity cost-recovery clause. Nuclear costs are deemed to be recovered up to the amount of the FPSC-approved projections, and the deferral of unrecovered nuclear costs accrues a carrying charge equal to PEF's approved AFUDC rate. Unrecovered nuclear costs eligible for accelerated recovery are deferred and recorded as regulatory assets in the Consolidated Balance Sheets and are amortized in the period the costs are collected from customers.

GOODWILL AND INTANGIBLE ASSETS

Goodwill is subject to at least an annual assessment for impairment by applying a two-step, fair value-based test. This assessment could result in periodic impairment charges. We perform our annual goodwill impairment test as of October 31 each year and perform an interim test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. Intangible assets are amortized based on the economic benefit of their respective lives.

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

Long-term debt premiums, discounts and issuance expenses are amortized over the terms of the debt issues. Any expenses or call premiums associated with the reacquisition of debt obligations by the Utilities are amortized over the applicable lives using the straight-line method consistent with ratemaking treatment (See Note 8A).

INCOME TAXES

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

Deferred income taxes have been provided for temporary differences. These occur when the book and tax carrying amounts of assets and liabilities differ. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. Credits for the production and sale of synthetic fuels are deferred credits to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns, and are included in income tax expense (benefit) of discontinued operations in the Consolidated Statements of Income. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority, including resolutions of any related appeals or litigation processes, based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount of the tax benefit that, in our judgment, is greater than 50 percent likely to be realized. Interest expense on tax deficiencies and uncertain tax positions is included in net interest charges, and tax penalties are included in other, net in the Consolidated Statements of Income.

DERIVATIVES

GAAP requires that an entity recognize all derivatives as assets or liabilities on the balance sheet and measure those instruments at fair value, unless the derivatives meet the GAAP criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related hedge criteria are met. We have elected not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. Certain economic derivative instruments (primarily fuel-related) receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. Cash flows from derivative instruments are generally included in cash provided by operating activities on the Statements of Cash Flows. See Note 18 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies, such as unfavorable results of litigation, when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, we record a loss contingency at the minimum amount in the range. With the exception of legal fees that are incremental direct costs of an environmental remediation effort, we do not accrue an estimate of legal fees when a contingent loss is initially recorded, but rather when the legal services are actually provided.

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

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

We review the recoverability of long-lived tangible and intangible assets whenever impairment indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an impairment indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

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

2. MERGER AGREEMENT

On January 8, 2011, Duke Energy and Progress Energy entered into an Agreement and Plan of Merger (the Merger Agreement). Pursuant to the Merger Agreement, Progress Energy will be acquired by Duke Energy in a stock-for-stock transaction (the Merger) and become a wholly owned subsidiary of Duke Energy. The Merger Agreement originally had a termination date of January 8, 2012, which has been extended by the parties to July 8, 2012.

Under the terms of the Merger Agreement, each share of Progress Energy common stock will be canceled and converted into the right to receive 2.6125 shares of Duke Energy common stock. Each outstanding option to acquire, and each outstanding equity award relating to, one share of Progress Energy common stock will be converted into an option to acquire, or an equity award relating to, 2.6125 shares of Duke Energy common stock. The board of directors of Duke Energy approved a reverse stock split, at a ratio of 1-for-3, subject to completion of the Merger. Accordingly, the adjusted exchange ratio is expected to be 0.87083 of a share of Duke Energy common stock, options and equity awards for each Progress Energy common share, option and equity award.

The combined company, to be called Duke Energy, will have an 18-member board of directors. The board will be comprised of, subject to their ability and willingness to serve, all 11 current directors of Duke Energy and seven current directors of Progress Energy. At the time of the Merger, William D. Johnson, Chairman, President and CEO of Progress Energy, will be President and CEO of Duke Energy, and James E. Rogers, Chairman, President and CEO of Duke Energy, will be the Executive Chairman of the board of directors of Duke Energy, subject to their ability and willingness to serve.

Consummation of the Merger is subject to customary conditions, including, among others things, approval by the shareholders of each company, expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and receipt of approvals, to the extent required, from the FERC, the Federal Communications Commission, the NRC, the NCUC, the Kentucky Public Service Commission and the SCPSC. Although there are no merger-specific regulatory approvals required in Indiana, Ohio or Florida, the companies will continue to update the public service commissions in those states on the Merger, as applicable and as required. The status of these matters is as follows, and we cannot predict the outcome of pending approvals:

Shareholder Approval

- On August 23, 2011, the Merger was approved by the shareholders of Progress Energy and Duke Energy.

Federal Regulatory Approvals

- On March 28, 2011, Progress Energy and Duke Energy submitted their Hart-Scott-Rodino filing with the U.S. Department of Justice (DOJ) for review under U.S. antitrust laws. The 30-day waiting period required by the Hart-Scott-Rodino Act expired without Progress Energy or Duke Energy having received requests for additional information. Progress Energy and Duke Energy have met their obligations under the Hart-Scott-Rodino Act. However, the period in which Progress Energy and Duke Energy may close the Merger consistent with their Hart-Scott-Rodino obligations will expire on April 26, 2012. Because the Merger is not expected to close on or before April 26, 2012, Progress Energy and Duke Energy intend to make new filings under the Hart-Scott-Rodino Act in order to be able to close the Merger after such date and continue to meet their obligations under the Hart-Scott-Rodino Act.
- On January 5, 2012, the Federal Communications Commission extended its approval of the Assignment of Authorization filings to transfer control of certain licenses. The extended approval expires on July 12, 2012.
- On September 30, 2011, the FERC, which assesses market power-related issues, conditionally approved the merger application filed by Progress Energy and Duke Energy. The approval is subject to the FERC's acceptance of market power mitigation measures to address the FERC's finding that the combined company could have an adverse effect on competition in the North Carolina and South Carolina wholesale power markets. Progress Energy and Duke Energy filed a market power mitigation plan with the FERC on October 17, 2011 that proposed a "virtual divestiture" under which power up to a certain amount would have been offered into the wholesale market rather than the sale or divestiture of physical assets. A virtual divestiture is one option the FERC indicated could be used to mitigate its market power concerns. On December 14, 2011, the FERC affirmed its conditional approval of the merger, but the FERC rejected the proposed market power mitigation plan. On February 22, 2012, Progress Energy and Duke Energy filed a notification with the NCUC of their intention to file a second market power mitigation plan with the FERC. The revised mitigation plan consists of two phases. Phase 1 is an interim mitigation that consists of a virtual divestiture whereby the companies propose a three-year plan to sell capacity and firm energy during the summer (June – August) and winter (December – February) to new market participants. Together, the companies would sell 800 MWs during summer off-peak hours, 475 MWs during summer peak hours, 225 MWs during winter off-peak hours, and 25 MWs during winter peak hours. The companies expect to secure contracts with potential buyers prior to filing the mitigation plan with the FERC. Phase 2 is a permanent mitigation that consists of constructing up to eight transmission projects in the combined service territories, which will expand the capability to import wholesale power into the Carolinas. The construction, preliminarily estimated to cost $75 million to $150 million, would begin after the Merger closes and take

approximately three years to complete. The companies will be working with the North Carolina Public Staff and the South Carolina Office of Regulatory Staff (ORS) on appropriate state ratemaking treatment associated with the measures in the revised market mitigation plan and other merger-related issues. Final agreement to the proposed mitigation efforts will be subject to resolution of the state ratemaking issues. The NCUC has up to 30 days to review the revised mitigation plan before it is filed with the FERC.

- On April 4, 2011, Progress Energy and Duke Energy made two additional filings with the FERC. The first filing is a Joint Dispatch Agreement, pursuant to which PEC and Duke Energy Carolinas will agree to jointly dispatch their generation facilities in order to achieve certain of the operating efficiencies expected to result from the Merger. The second filing is a joint open access transmission tariff (OATT) pursuant to which PEC and Duke Energy Carolinas will agree to provide transmission service over their transmission facilities under a single transmission rate. On December 14, 2011, in conjunction with the aforementioned decision on the proposed market power mitigation plan, the FERC dismissed these related filings as not ripe for decision. As allowed under the FERC's December 14, 2011 order, Progress Energy and Duke Energy intend to refile the Joint Dispatch Agreement and OATT upon filing of the second market power mitigation plan with the FERC.
- On December 2, 2011, the NRC approved the filing requesting an indirect transfer of control of licenses for Progress Energy's nuclear facilities to include Duke Energy as the ultimate parent corporation on these licenses.

State Regulatory Approvals

- On April 4, 2011, Progress Energy and Duke Energy filed a merger approval application and an application for approval of a Joint Dispatch Agreement between PEC and Duke Energy Carolinas with the NCUC. On September 2, 2011, the North Carolina Public Staff filed a settlement agreement with the NCUC. On September 6, 2011, Progress Energy and Duke Energy signed a settlement with the ORS, a party to the North Carolina proceedings to resolve the ORS's issues in the North Carolina proceeding. Under the settlement agreement with the North Carolina Public Staff, Progress Energy and Duke Energy will provide $650 million in system fuel cost savings for customers in North Carolina and South Carolina over the five years following the close of the Merger, maintain their current level of community support in North Carolina for the next four years, and provide $15 million for low-income energy assistance and workforce development in North Carolina. The settlement agreement also provides that direct merger-related expenses will not be recovered from customers; however, PEC may request recovery of costs incurred to create operational savings. The NCUC held hearings regarding the application on September 20-22, 2011. On November 23, 2011, Progress Energy and Duke Energy filed proposed orders and briefs with the NCUC. The docket will remain open pending the FERC's issuance of its final orders on the merger-related actions before the FERC.
- On April 25, 2011, Progress Energy and Duke Energy filed an application for approval of the merger of PEC and Duke Energy Carolinas and an application for approval of a Joint Dispatch Agreement between PEC and Duke Energy Carolinas with the SCPSC. On September 13, 2011, Progress Energy and Duke Energy withdrew the application of the merger of PEC and Duke Energy Carolinas, as the merger of these entities is not likely to occur for several years after the close of the Merger. The SCPSC held hearings regarding the application for approval of the Joint Dispatch Agreement on December 12, 2011. During the hearing, PEC, Duke Energy Carolinas and the ORS agreed to terminate the settlement agreement, which resolved the ORS's issues in the NCUC merger proceeding, and replaced it with a commitment by PEC and Duke Energy Carolinas to provide PEC's and Duke Energy Carolinas' retail customers in South Carolina pro rata benefits equivalent to those approved by the NCUC in its order ruling upon PEC's and Duke Energy Carolinas' merger application. The docket will remain open pending the FERC's issuance of its final orders on the merger-related actions before the FERC.
- On October 28, 2011, the Kentucky Public Service Commission approved Progress Energy's and Duke Energy's merger-related settlement agreement with the Attorney General of the Commonwealth of Kentucky.

The Merger Agreement includes certain restrictions, limitations and prohibitions as to actions we may or may not take in the period prior to consummation of the Merger. Among other restrictions, the Merger Agreement limits our total capital spending, limits the extent to which we can obtain financing through long-term debt and equity, and we may not, without the prior approval of Duke Energy, increase our quarterly common stock dividend of $0.62 per share. In the fourth quarter of 2011, our board of directors declared a partial dividend payment to Progress Energy shareholders to align Progress Energy's dividend payment schedule with that of Duke Energy such that following the closing of the Merger, all stockholders of the combined company would receive dividends under the Duke Energy dividend schedule.

Certain substantial changes in ownership of Progress Energy, including the Merger, can impact the timing of the utilization of tax credit carry forwards and net operating loss carry forwards (See Note 15).

The Merger Agreement contains certain termination rights for both companies; under specified circumstances we may be required to pay Duke Energy $400 million and Duke Energy may be required to pay us $675 million. In addition, under specified circumstances each party may be required to reimburse the other party for up to $30 million of merger-related expenses.

Certain Progress Energy shareholders filed class action lawsuits in the state and federal courts in North Carolina against Progress Energy and each of the members of Progress Energy's board of directors, which have been subsequently settled (See Note 22D).

In connection with the Merger, we established an employee retention plan for certain eligible employees. Payments under the plan are contingent upon the consummation of the Merger and the employees' continued employment through a specified time period following the Merger. These payments will be recorded as compensation expense following consummation of the Merger. We estimate the costs of the retention plan to be $14 million.

In connection with the Merger, we announced plans to offer a voluntary severance plan (VSP) to certain eligible employees. Payments under the plan are contingent upon the consummation of the Merger. The window for eligible employees to request a voluntary end to their employment under the VSP opened on November 7, 2011, and ended on November 30, 2011. Approximately 650 employees requested and were approved for separation under the VSP in December 2011. The cost of the VSP is estimated to be between $90 million to $100 million, including $65 million to $70 million and $25 million to $30 million related to PEC and PEF, respectively. If the employee is not required to work for a significant period after the consummation of the Merger, the costs of any benefits paid under the VSP will be measured and recorded upon consummation of the Merger. If a significant retention period exists, the costs of benefits equal to what would be paid under our existing severance plan will be measured and recorded upon consummation of the Merger. Any additional benefits paid under the VSP will be recorded ratably over the remaining service periods of the affected employees.

In addition, we evaluated our business needs for office space after the Merger and formulated an exit plan to vacate one of our corporate headquarters buildings. Under the plan, we will gradually vacate the premises beginning in the fourth quarter of 2011 through January 1, 2013. In December 2011, we executed an agreement with a third party to sublease the building until 2035. The estimated exit cost liability associated with this exit plan is $17 million for us, of which $12 million of expense is attributable to PEC and $5 million to PEF. The exit cost liability will be recognized proportionately as we vacate the premises. During the fourth quarter of 2011, we recorded exit cost liabilities of $5 million for us, of which $3 million of expense is attributable to PEC and $2 million to PEF. These costs are included in merger and integration-related costs.

In connection with the Merger, we incurred merger and integration-related costs of $46 million, net of tax, including $25 million, net of tax, and $21 million, net of tax, at PEC and PEF, respectively, for the year ended December 31, 2011. These costs are included in operations and maintenance (O&M) expense in our Consolidated Statements of Income.

3. NEW ACCOUNTING STANDARDS

FAIR VALUE MEASUREMENT AND DISCLOSURES

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," which amends Accounting Standards Codification (ASC) 820 to clarify certain existing disclosure requirements and to require a number of additional disclosures, including amounts and reasons for significant transfers between the three levels of the fair value hierarchy, and presentation of certain information in the reconciliation of recurring Level 3 measurements on a gross basis. ASU 2010-06 was effective for us on January 1, 2010, with certain disclosures effective January 1, 2011. The adoption of ASU 2010-06 resulted in additional disclosures in the notes to the financial statements but did not have an impact on our or the Utilities' financial position, results of operations or cash flows.

In May 2011, the FASB issued ASU 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs," which amends ASC 820 to develop a single, converged fair value framework between GAAP and International Financial Reporting Standards (IFRS). ASU 2011-04 is effective prospectively for us on January 1, 2012. The adoption of ASU 2011-04 will result in changes in certain fair value measurement principles, as well as additional disclosure in the notes to the financial statements. However, the impact of adoption is not expected to be significant to our or the Utilities' financial position, results of operations or cash flows.

GOODWILL IMPAIRMENT TESTING

In September 2011, the FASB issued ASU 2011-08, "Testing Goodwill for Impairment," which amends the guidance in ASC 350 on testing goodwill for impairment. Under the revised guidance, we have the option of performing a qualitative assessment before calculating the fair value of our reporting units. If it is determined in the qualitative assessment that it is more likely than not that the fair value of the reporting unit is less than its carrying amount, we would proceed to the two-step goodwill impairment test. Otherwise, no further impairment testing would be required. ASU 2011-08 is effective for us on January 1, 2012. The adoption of ASU 2011-08 is effective for both interim and annual goodwill tests and will give us the option to perform the qualitative assessment to determine the need for a two-step goodwill impairment test. The impact of the adoption is not expected to be significant to our or the Utilities' financial position, results of operations or cash flows.

DISCLOSURES ABOUT OFFSETTING ASSETS AND LIABILITIES

In December 2011, the FASB issued ASU 2011-11, "Disclosures About Offsetting Assets and Liabilities," which adds new disclosures to help financial statement users better understand the impact of offsetting arrangements on our balance sheet. The adoption of ASU 2011-11 will add disclosures showing both gross and net information about instruments and transactions eligible for offset in the balance sheet and instruments and transactions subject to an agreement similar to a master netting arrangement. ASU 2011-11 is effective for us on January 1, 2013, and will be retroactively applied.

4. DIVESTITURES

We have completed our business strategy of divesting nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. Included in discontinued operations, net of tax are amounts related to adjustments of our prior sales of diversified businesses. These adjustments are generally due to guarantees and indemnifications provided for certain legal, tax and environmental matters. See Note 22C for further discussion of our guarantees. The ultimate resolution of these matters could result in additional adjustments in future periods. The information below presents the impacts of the divestitures on net income attributable to controlling interests.

A. TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

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

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates. As a result, during the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations. See Note 22D for further discussion.

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

(in millions)	**2011**	2010	2009
Loss before income taxes and noncontrolling interest	**$ (8)**	$ (11)	$ (125)
Income tax benefit, including tax credits	**3**	5	47
Loss from discontinued operations attributable to controlling interests	**$ (5)**	$ (6)	$ (78)

The total income tax benefit presented in the preceding table includes deferred income tax benefit (expense) of $28 million, $124 million and $(86) million for the years ended December 31, 2011, 2010 and 2009, respectively, related to synthetic fuels tax credits.

B. OTHER DIVERSIFIED BUSINESSES

Also included in discontinued operations are amounts related to adjustments of our prior sales of other diversified businesses. During the years ended December 31, 2011, 2010 and 2009, gains and losses related to post-closing adjustments and pre-divestiture contingencies of other diversified businesses were not material to our results of operations.

5. PROPERTY, PLANT AND EQUIPMENT

A. UTILITY PLANT

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

	Depreciable	Progress Energy		PEC		PEF	
(in millions)	Lives	**2011**	2010	**2011**	2010	**2011**	2010
Production plant	3-41	**$ 16,728**	$ 16,042	**$ 9,978**	$ 9,354	**$ 6,585**	$ 6,523
Transmission plant	7-75	**3,853**	3,530	**1,825**	1,626	**2,028**	1,904
Distribution plant	13-67	**9,053**	8,715	**4,887**	4,687	**4,166**	4,028
General plant and other	5-35	**1,431**	1,421	**749**	721	**682**	700
Utility plant in service		**$ 31,065**	$ 29,708	**$ 17,439**	$ 16,388	**$ 13,461**	$ 13,155

Generally, electric utility plant at PEC and PEF, other than nuclear fuel, is pledged as collateral for the first mortgage bonds of PEC and PEF, respectively (See Note 12). In the 2012 settlement agreement, PEF agreed to remove PEF's Crystal River Unit No. 3 Nuclear Plant (CR3) from rate base and will reclassify CR3 to a regulatory asset and suspend depreciation expense (See Note 8C).

As discussed in Note 8B, PEC intends to retire no later than December 31, 2013, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 megawatts (MW) at four sites. On October 1, 2011, PEC retired the Weatherspoon coal-fired generating units. At December 31, 2011, the $15 million net carrying value of this retired facility is included in regulatory assets on the Consolidated Balance Sheets.

AFUDC is charged to the cost of the plant for certain projects in accordance with the regulatory provisions for each jurisdiction. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 8.7 percent in 2011 and 9.2 percent in 2010 and 2009. The composite AFUDC rate for PEF's electric utility plant was 7.4 percent, effective beginning April 1, 2010, based on its authorized return on equity (ROE) approved in the 2010 settlement agreement. This rate was unchanged by the 2012 settlement agreement (See Note 8C). Prior to April 1, 2010, the composite AFUDC rate for PEF's electric utility plant was 8.8 percent.

Our depreciation provisions on utility plant and amortization of other utility plant, net, as a percent of average depreciable property other than nuclear fuel, were 2.3 percent, 2.0 percent and 2.4 percent in 2011, 2010 and 2009, respectively. The depreciation provisions related to utility plant and amortization of other utility plant, net were $675 million, $635 million and $626 million in 2011, 2010 and 2009, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5C) and regulatory approved expenses (See Notes 8 and 21).

PEC's depreciation provisions on utility plant and amortization of other utility plant, net, as a percent of average depreciable property other than nuclear fuel, were 2.1 percent for 2011, 2010 and 2009. The depreciation provisions related to utility plant and amortization of other utility plant, net were $360 million, $338 million and $328 million in 2011, 2010 and 2009, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5C) and regulatory approved expenses (See Note 8B).

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4 percent in 2011, 1.9 percent in 2010 and 2.7 percent in 2009. The depreciation provisions related to utility plant were $315 million, $297 million and $299 million in 2011, 2010 and 2009, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5C) and regulatory approved expenses (See Note 8C).

During 2010, PEF updated the depreciation rates approved by the FPSC in the 2009 base rate case. The rate change was effective January 1, 2010, and resulted in a decrease in depreciation expense of $43 million for 2010. Additionally, in December 2010, PEF filed the FPSC-approved depreciation rates with the FERC for use in its formula transmission rate for its OATT. The FERC filing requested depreciation rates be applied retroactively to January 1, 2010, whereby, if approved, the depreciation rate changes would result in a reduction to the depreciation expense charged to PEF's OATT customers, beginning June 1, 2011. The FERC on July 15, 2011, rejected the proposed adjustments to depreciation reserves.

Nuclear fuel, net of amortization at December 31, 2011 and 2010, was $767 million and $674 million, respectively, for Progress Energy; $540 million and $480 million, respectively, for PEC; and $227 million and $194 million, respectively, for PEF. The amount not yet in service at December 31, 2011 and 2010, was $575 million and $367 million, respectively, for Progress Energy; $322 million and $199 million, respectively, for PEC; and $253 million and $168 million, respectively, for PEF. Amortization of nuclear fuel costs, including disposal costs associated with obligations to the DOE and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, was $160 million, $132 million and $159 million for the years ended December 31, 2011, 2010 and 2009, respectively. This amortization expense is included in fuel used in electric generation in the Consolidated Statements of Income. PEC's amortization of nuclear fuel costs for the years ended December 31, 2011, 2010 and 2009 was $160 million, $132 million and $134 million, respectively. PEF's amortization of nuclear fuel costs for the year ended December 31, 2009, was $25 million. PEF did not have any amortization of nuclear fuel costs for the years ended December 31, 2011 and 2010, due to the CR3 outage (See Note 8C).

PEF's construction work in progress related to certain nuclear projects receives regulatory treatment. At December 31, 2011, PEF had $555 million of accelerated recovery of construction work in progress, of which $177 million was a component of a nuclear cost-recovery clause regulatory asset. At December 31, 2010, PEF had $519 million of accelerated recovery of construction work in progress, of which $237 million was a component of a nuclear cost-recovery clause regulatory asset. See Note 8C for further discussion of PEF's nuclear cost recovery.

B. JOINT OWNERSHIP OF GENERATING FACILITIES

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

PEC's and PEF's ownership interests in the jointly owned generating facilities are listed below with related information at December 31:

(in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
2011					
PEC	**Mayo**	**83.83 %**	**$ 807**	**$ 296**	**$ 13**
PEC	**Harris**	**83.83 %**	**3,254**	**1,635**	**66**
PEC	**Brunswick**	**81.67 %**	**1,739**	**951**	**52**
PEC	**Roxboro Unit 4**	**87.06 %**	**733**	**470**	**12**
PEF	**Crystal River Unit 3**	**91.78 %**	**909**	**498**	**803**
PEF	**Intercession City Unit P11**	**66.67 %**	**23**	**12**	**-**
2010					
PEC	Mayo	83.83 %	$ 798	$ 294	$ 8
PEC	Harris	83.83 %	3,255	1,604	16
PEC	Brunswick	81.67 %	1,702	939	38
PEC	Roxboro Unit 4	87.06 %	706	457	22
PEF	Crystal River Unit 3	91.78 %	901	497	648
PEF	Intercession City Unit P11	66.67 %	23	11	-

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

In the tables above, construction work in progress for CR3 is not reduced by the accelerated recovery of qualifying project costs under the FPSC nuclear cost-recovery rule (see Note 8C).

C. ASSET RETIREMENT OBLIGATIONS

At December 31, 2011 and 2010, our asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant, net of accumulated depreciation totaled $87 million and $90 million, respectively. PEC had immaterial asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant at December 31, 2011 and 2010. Primarily due to the impact of updated escalation factors in 2010, as discussed below, at December 31, 2011 and 2010, PEF had no asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant. At December 31, 2011 and 2010, additional PEF-related asset retirement costs, net of accumulated depreciation, of $87 million and $90 million, respectively, were recorded at Progress Energy as purchase accounting adjustments recognized when we purchased Florida Progress Corporation (Florida Progress) in 2000.

The fair value of funds set aside in the Utilities' nuclear decommissioning trust (NDT) funds for the nuclear decommissioning liability totaled $1.647 billion and $1.571 billion at December 31, 2011 and 2010, respectively (See Notes 13 and 14). The fair value of funds set aside in the NDT funds for the nuclear decommissioning liability totaled $1.088 billion and $1.017 billion at December 31, 2011 and 2010, respectively, for PEC and $559 million and $554 million, respectively, for PEF (See Notes 13 and 14). Net NDT unrealized gains are included in regulatory liabilities (See Note 8A).

Progress Energy's and PEC's nuclear decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2011, 2010 and 2009. As discussed below, PEF has suspended its accrual for nuclear decommissioning. Management believes that nuclear decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning.

We recognized a benefit of $98 million in 2011 and expenses of $87 million and $141 million in 2010 and 2009, respectively, for the disposal or removal of utility assets that do not meet the definition of AROs, which are included in depreciation, amortization and accretion expense. PEC's related expenses were $125 million, $122 million and $106 million in 2011, 2010 and 2009, respectively. Due to a $250 million and $60 million cost of removal credit in 2011 and 2010, respectively, as allowed by the 2010 settlement agreement approved by the FPSC (See Note 8C), PEF recognized a benefit of $223 million and $35 million in 2011 and 2010, respectively. PEF's related expenses were $35 million in 2009.

The Utilities recognize removal, nonirradiated decommissioning and dismantlement of fossil generation plant costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 8A). At December 31, such costs consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Removal costs	**$ 1,302**	$ 1,503	**$ 1,065**	$ 1,000	**$ 237**	$ 503
Nonirradiated decommissioning costs	**223**	233	**185**	172	**38**	61
Dismantlement costs	**125**	121	**-**	-	**125**	121
Non-ARO cost of removal	**$ 1,650**	$ 1,857	**$ 1,250**	$ 1,172	**$ 400**	$ 685

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC received a new site-specific estimate of decommissioning costs for Robinson Nuclear Plant (Robinson) Unit No. 2, Brunswick Nuclear Plant (Brunswick) Units No. 1 and No. 2, and Harris, in December 2009, which was filed with the NCUC on March 16, 2010. PEC's estimate is based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2009 dollars, were $687 million for Unit No. 2 at Robinson, $591 million for Brunswick Unit No. 1, $585 million for Brunswick Unit No. 2 and $1.126 billion for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. See Note 8D for information about the NRC operating licenses held by PEC.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF received a new site-specific estimate of decommissioning costs for CR3 in October 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing. However, the FPSC deferred review of PEF's nuclear decommissioning study from the rate case to be addressed in 2010 in order for FPSC staff to assess PEF's study in combination with other utilities anticipated to submit nuclear decommissioning studies in 2010. PEF was not required to prepare a new site-specific nuclear decommissioning study in 2010; however, PEF was required to update the 2008 study with the most currently available escalation rates in 2010, which was filed with the FPSC in December 2010. We expect the FPSC to issue an order in 2012. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2008 dollars, is $751 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. See Note 8D for information about the NRC operating license held by PEF for CR3. Based on the 2008 estimate, assumed operating license renewal and updated escalation factors in 2010, PEF decreased its asset retirement cost to zero and its ARO liability by approximately $37 million in 2010. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended under the terms of previous base rate settlement agreements. PEF expects to continue this suspension based on its 2010 nuclear decommissioning filing. No nuclear decommissioning reserve accrual is recorded at PEF following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF received an updated fossil dismantlement study estimate in 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing. As a result of the base rate case, the FPSC approved an annual fossil dismantlement accrual of $4 million. PEF's reserve for fossil plant dismantlement was approximately $148 million and $144 million at December 31, 2011 and 2010, including amounts in the ARO liability for asbestos abatement, discussed below.

PEC and PEF have recognized ARO liabilities related to asbestos abatement costs. The ARO liabilities related to asbestos abatement costs were $23 million and $26 million at December 31, 2011 and 2010, respectively, at PEC and $29 million and $27 million at December 31, 2011 and 2010, respectively, at PEF.

Additionally, PEC and PEF have recognized ARO liabilities related to landfill capping costs. The ARO liabilities related to landfill capping costs were $6 million and $3 million at December 31, 2011 and 2010, respectively, at PEC and $7 million and $6 million at December 31, 2011 and 2010, respectively, at PEF.

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

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

(in millions)	Progress Energy	PEC	PEF
Asset retirement obligations at January 1, 2010	$ 1,170	$ 801	$ 369
Additions	4	4	-
Accretion expense	65	46	19
Revisions to prior estimates	(39)	(2)	(37)
Asset retirement obligations at December 31, 2010	1,200	849	351
Accretion expense	**67**	**49**	**18**
Revisions to prior estimates	**(2)**	**(2)**	**-**
Asset retirement obligations at December 31, 2011	**$ 1,265**	**$ 896**	**$ 369**

D. INSURANCE

The Utilities are members of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities. Under the primary program, each company is insured for $500 million at each of its respective nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $1.750 billion on each nuclear plant.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under this program, following a 12-week deductible period, for 52 weeks in the amounts ranging from $3.5 million to $4.5 million per week. Additional weeks of coverage ranging from 71 weeks to 110 weeks are provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $29 million with respect to the primary coverage, $40 million with respect to the decontamination, decommissioning and excess property coverage, and $25 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate the plant, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above. At December 31, 2011, PEF has an outstanding claim with NEIL for CR3 (See Notes 6 and 8C).

Both of the Utilities are insured against public liability for a nuclear incident up to $12.595 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from each insured nuclear incident exceed the primary level of coverage provided by American Nuclear Insurers, each company would be subject to pro rata assessments of up to $117.5 million for each reactor owned for each incident. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $17.5 million per reactor owned per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before August 29, 2013.

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

The Utilities self-insure their transmission and distribution lines against loss due to storm damage and other natural disasters. PEF maintains a storm damage reserve and has a regulatory mechanism to recover the costs of named storms on an expedited basis (See Note 8C).

For loss or damage to non-nuclear properties, excluding self-insured transmission and distribution lines, the Utilities are insured under an all-risk property insurance program with a total limit of $600 million per loss. The basic deductible is $2.5 million per loss, and there is no outage or replacement power coverage under this program.

6. RECEIVABLES

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

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Trade accounts receivable	**$ 520**	$ 651	**$ 276**	$ 346	**$ 244**	$ 303
Unbilled accounts receivable	**157**	223	**102**	136	**55**	87
Other receivables	**168**	75	**123**	47	**20**	12
NEIL receivable (Note 8C)	**71**	119	**-**	-	**71**	119
Allowance for doubtful receivables	**(27)**	(35)	**(9)**	(10)	**(18)**	(25)
Total receivables, net	**$ 889**	$ 1,033	**$ 492**	$ 519	**$ 372**	$ 496

Other receivables for Progress Energy and PEC above include $92 million at December 31, 2011, related to the award from the DOE for asserted damages associated with spent nuclear fuel (See Note 22D).

7. INVENTORY

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Fuel for production	**$ 681**	$ 542	**$ 323**	$ 192	**$ 358**	$ 350
Materials and supplies	**747**	676	**446**	395	**301**	281
Emission allowances	**4**	8	**1**	3	**3**	5
Other	**6**	-	**5**	-	**1**	-
Total inventory	**$ 1,438**	$ 1,226	**$ 775**	$ 590	**$ 663**	$ 636

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits on the Consolidated Balance Sheets for Progress Energy, PEC and PEF of $28 million, $4 million and $24 million, respectively, at December 31, 2011. Long-term emission allowances for Progress Energy, PEC and PEF were $33 million, $5 million and $28 million, respectively, at December 31, 2010.

8. REGULATORY MATTERS

On January 8, 2011, Progress Energy and Duke Energy entered into the Merger Agreement. See Note 2 for regulatory information related to the Merger with Duke Energy.

A. REGULATORY ASSETS AND LIABILITIES

As regulated entities, the Utilities are subject to the provisions of GAAP for regulated operations. 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. Regulatory assets may be recorded for certain employee benefit costs of unregulated affiliates that will be allocated to the Utilities and recovered through rates of the Utilities. Our and the Utilities' ability to continue to meet the criteria for application of GAAP for regulated operations could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that GAAP for regulated operations no longer applies to a separable portion of our operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, such an event would require the Utilities to determine if any impairment to other assets, including utility plant, exists and write down impaired assets to their fair values.

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

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

PROGRESS ENERGY

(in millions)		**2011**		2010
Deferred fuel costs – current (Notes 8B and 8C)	**$**	**275**	$	169
Nuclear deferral (Note 8C)		**-**		7
Total current regulatory assets		**275**		176
Nuclear deferral (Note 8C)[a]		**117**		178
Deferred impact of ARO (Note 5C)[b]		**137**		122
Income taxes recoverable through future rates[c]		**352**		302
Loss on reacquired debt[d]		**29**		31
Postretirement benefits (Note 17)[e]		**1,506**		1,105
Derivative mark-to-market adjustment (Note 18A)[f]		**708**		505
DSM/Energy-efficiency deferral (Note 8B)[g]		**92**		57
Other		**84**		74
Total long-term regulatory assets		**3,025**		2,374
Environmental (Note 8C)		**(7)**		(45)
Energy conservation (Note 8C)		**(19)**		(11)
Nuclear deferral (Note 8C)		**(15)**		-
Other current regulatory liabilities		**(7)**		(3)
Total current regulatory liabilities		**(48)**		(59)
Amount to be refunded to customers (Note 8C)[h]		**(288)**		-
Non-ARO cost of removal (Note 5C)[b]		**(1,650)**		(1,857)
Deferred impact of ARO (Note 5C)[b]		**(146)**		(143)
Net nuclear decommissioning trust unrealized gains (Note 5C)[i]		**(412)**		(421)
Storm reserve (Note 8C)[j]		**(132)**		(136)
Other		**(72)**		(78)
Total long-term regulatory liabilities		**(2,700)**		(2,635)
Net regulatory assets (liabilities)	**$**	**552**	$	(144)

PEC

(in millions)		**2011**		2010
Deferred fuel costs – current (Note 8B)	**$**	**31**	$	71
Deferred impact of ARO (Note 5C)[b]		**124**		112
Income taxes recoverable through future rates[c]		**140**		103
Loss on reacquired debt[d]		**12**		13
Postretirement benefits (Note 17)[e]		**691**		545
Derivative mark-to-market adjustment (Note 18A)[f]		**200**		121
DSM/Energy-efficiency deferral (Note 8B)[g]		**92**		57
Other		**51**		36
Total long-term regulatory assets		**1,310**		987
Deferred fuel costs – current (Note 8B)		**(2)**		-
Non-ARO cost of removal (Note 5C)[b]		**(1,250)**		(1,172)
Net nuclear decommissioning trust unrealized gains (Note 5C)[i]		**(266)**		(267)
Other		**(27)**		(22)
Total long-term regulatory liabilities		**(1,543)**		(1,461)
Net regulatory liabilities	**$**	**(204)**	$	(403)

PEF

(in millions)		2011		2010
Deferred fuel costs – current (Note 8C)	**$**	**244**	$	98
Nuclear deferral (Note 8C)		**-**		7
Total current regulatory assets		**244**		105
Nuclear deferral (Note 8C)[a]		**117**		178
Income taxes recoverable through future rates[c]		**212**		199
Loss on reacquired debt[d]		**17**		18
Postretirement benefits (Note 17)[e]		**702**		560
Derivative mark-to-market adjustment (Note 18A)[f]		**508**		384
Other		**46**		48
Total long-term regulatory assets		**1,602**		1,387
Environmental (Note 8C)		**(7)**		(45)
Energy conservation (Note 8C)		**(19)**		(11)
Nuclear deferral (Note 8C)		**(15)**		-
Other current regulatory liabilities		**(5)**		(3)
Total current regulatory liabilities		**(46)**		(59)
Amount to be refunded to customers (Note 8C)[h]		**(288)**		-
Non-ARO cost of removal (Note 5C)[b]		**(400)**		(685)
Deferred impact of ARO (Note 5C)[b]		**(45)**		(47)
Net nuclear decommissioning trust unrealized gains (Note 5C)[i]		**(146)**		(154)
Storm reserve (Note 8C)[j]		**(132)**		(136)
Other		**(60)**		(62)
Total long-term regulatory liabilities		**(1,071)**		(1,084)
Net regulatory assets	**$**	**729**	$	349

The recovery and amortization periods for these regulatory assets and (liabilities) at December 31, 2011, are as follows:

(a) Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding five years.

(b) Asset retirement and removal liabilities are recorded over the related property lives, which may range up to 65 years, and will be settled and adjusted following completion of the related activities.

(c) Income taxes recoverable through future rates are recovered over the related property lives, which may range up to 65 years.

(d) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 30 years.

(e) Recovered and amortized over the remaining service period of employees. In accordance with a 2009 FPSC order, PEF's 2009 deferred pension expense of $34 million will be amortized to the extent that annual pension expense is less than the $27 million allowance provided for in base rates (See Note 17).

(f) Related to derivative unrealized gains and losses that are recorded as a regulatory liability or asset, respectively, until the contracts are settled. After contract settlement and consumption of the related fuel, the realized gains or losses are passed through the fuel cost-recovery clause.

(g) Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding 10 years.

(h) Recorded as a result of the 2012 settlement agreement to be refunded to customers through the fuel clause over four years beginning in 2013 (see Note 8C).

(i) Related to unrealized gains and losses on NDT funds that are recorded as a regulatory asset or liability, respectively, until the funds are used to decommission a nuclear plant.

(j) Utilized as storm restoration expenses are incurred.

B. PEC RETAIL RATE MATTERS

BASE RATES

PEC's base rates are subject to the regulatory jurisdiction of the NCUC and SCPSC. In PEC's most recent base rate cases in 1988, the NCUC and the SCPSC each authorized a ROE of 12.75 percent.

COST RECOVERY FILINGS

On November 14, 2011, the NCUC approved PEC's settlement agreement for an $85 million increase in the fuel rate charged to its North Carolina retail ratepayers, driven by rising fuel prices. The settlement agreement updated certain costs from PEC's original filing and included the impact of a $24 million disallowance of replacement power costs resulting from prior-year performance of PEC's nuclear plants. The increase was effective December 1, 2011, and increased residential electric bills by $2.75 per 1,000 kilowatt-hours (kWh) for fuel cost recovery. Also on November 14, 2011, the NCUC approved PEC's request for a $24 million increase in the demand-side management (DSM) and EE rate charged to its North Carolina ratepayers. The increase was effective December 1, 2011, and increased the residential electric bills by $1.08 per 1,000 kWh for DSM and EE cost recovery. On November 10, 2011, the NCUC approved PEC's request for a $9 million increase for North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS). The increase was effective December 1, 2011, and decreased the residential electric bills by $0.02 per 1,000 kWh. The residential NC REPS rate decreased while the total amount to be recovered increased due to the allocation of the NC REPS recovery between customer classes. The net impact of the settlement agreement and filings results in an average increase in residential electric bills of 3.7 percent. At December 31, 2011, PEC's North Carolina deferred fuel and DSM/EE balances were $31 million and $78 million, respectively.

On June 29, 2011, the SCPSC approved a $22 million increase in the fuel rate charged to its South Carolina ratepayers, driven by rising fuel prices. The increase was effective July 1, 2011, and increased residential electric bills by $3.45 per 1,000 kWh. Also on June 29, 2011, the SCPSC approved a $4 million increase in the DSM and EE rate. The increase was effective July 1, 2011, and increased residential electric bills by $1.25 per 1,000 kWh. The net impact of the two filings resulted in an average increase in residential electric bills of 4.7 percent. At December 31, 2011, PEC's South Carolina deferred fuel and DSM/EE balances were $(2) million and $14 million, respectively.

OTHER MATTERS

<u>Construction of Generating Facilities</u>

On June 1, 2011, a newly constructed 600-MW combined cycle natural gas-fueled unit at the Smith Energy Complex was placed in service.

On October 22, 2009, the NCUC issued its order granting PEC a Certificate of Public Convenience and Necessity to construct an approximately 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C. PEC projects that the generating facility will be in service by January 2013.

On June 9, 2010, the NCUC issued its order granting PEC a Certificate of Public Convenience and Necessity to construct an approximately 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C., to replace the existing coal-fired generation at this site. PEC projects that the generating facility will be in service in December 2013.

<u>Planned Retirements of Generating Facilities</u>

PEC filed a plan with the NCUC and the SCPSC to retire all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. On October 1, 2011, PEC retired the Weatherspoon coal-fired generating units. PEC expects to retire the remaining coal-fired facilities by the end of 2013.

The net carrying value of the three remaining facilities at December 31, 2011, of $163 million is included in other utility plant, net on the Consolidated Balance Sheets. Consistent with ratemaking treatment, PEC will continue to depreciate each plant using the current depreciation lives and rates on file with the NCUC and the SCPSC until the earlier of the plant's retirement or PEC's completion and filing of a new depreciation study on or before March 31, 2013. The net carrying value of the retired facility at December 31, 2011, of $15 million is included in regulatory assets on the Consolidated Balance Sheets. PEC expects to include the four facilities' remaining net carrying value in rate base after retirement. The final recovery periods may change in connection with the regulators' determination of the recovery of the remaining net carrying value.

C. PEF RETAIL RATE MATTERS

CR3 OUTAGE

In September 2009, CR3 began an outage for normal refueling and maintenance as well as an uprate project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination (or separation) within the concrete at the periphery of the containment building, which resulted in an extension of the outage. After analysis, PEF determined that the concrete delamination at CR3 was caused by redistribution of stresses in the containment wall that occurred when PEF created an opening to accommodate the replacement of the unit's steam generators. In March 2011, the work to return the plant to service was suspended after monitoring equipment at the repair site identified a new delamination that occurred in a different section of the outer wall after the repair work was completed and during the late stages of retensioning the containment building. CR3 has remained out of service while PEF conducted an engineering analysis and review of the new delamination and evaluated repair options. Subsequent to March 2011, monitoring equipment has detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations could occur during the repair process.

PEF analyzed multiple repair options as well as early decommissioning and believes, based on the information and analyses conducted to date, that repairing the unit is the best option. PEF engaged outside engineering consultants to perform the analysis of possible repair options for the containment building. The consultants analyzed 22 potential repair options and ultimately narrowed those to four. PEF, along with other independent consultants, reviewed the four options for technical issues, constructability, and licensing feasibility as well as cost.

Based on that initial analysis, PEF selected the best repair option, which would entail systematically removing and replacing concrete in substantial portions of the containment structure walls. The planned option does not include the area where concrete was replaced during the initial repair. The preliminary cost estimate for this repair as filed with the FPSC on June 27, 2011, is between $900 million and $1.3 billion. Engineering design of the repair is under way. PEF will update the current estimate as this work is completed.

PEF is moving forward systematically and will perform additional detailed engineering analyses and designs, which could affect any repair plan. This process will lead to more certainty for the cost and schedule of the repair. PEF will continue to refine and assess the plan, and the prudence of continuing to pursue it, based on new developments and analyses as the process moves forward. Under this repair plan, PEF estimates that CR3 will return to service in 2014. The decision related to repairing or decommissioning CR3 is complex and subject to a number of unknown factors, including but not limited to, the cost of repair and the likelihood of obtaining NRC approval to restart CR3 after repair. A number of factors could affect the repair plan, the return-to-service date and costs, including regulatory reviews, final engineering designs, contract negotiations, the ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis and other developments.

PEF maintains insurance for property damage and incremental costs of replacement power resulting from prolonged accidental outages through NEIL as discussed in Note 5D. NEIL has confirmed that the CR3 initial delamination is a covered accident but has not yet made a determination as to coverage for the second delamination. Following a 12-week deductible period, the NEIL program provided reimbursement for replacement power costs for 52 weeks at $4.5 million per week, through April 9, 2011. An additional 71 weeks of coverage, which runs through August 2012, is provided at $3.6 million per week. Accordingly, the NEIL program provides replacement power coverage of up to $490 million per event. Actual replacement power costs have exceeded the insurance coverage through December 31,

2011. PEF anticipates that future replacement power costs will continue to exceed the insurance coverage. PEF also maintains insurance coverage through NEIL's accidental property damage program, which provides insurance coverage up to $2.25 billion with a $10 million deductible per claim.

PEF is continuing to work with NEIL for recovery of applicable repair costs and associated replacement power costs. PEF has not yet received a definitive determination from NEIL about the insurance coverage related to the second delamination. In addition, no replacement power reimbursements were received from NEIL in the second half of 2011. These considerations led us to conclude that at December 31, 2011, it was not probable that NEIL will voluntarily pay the full coverage amounts we believe they owe under the applicable insurance policies. Given the circumstances, accounting standards require full recovery to be probable to recognize an insurance receivable. Therefore, PEF has suspended recording any further insurance receivables from NEIL related to the second delamination and removed the associated $222 million NEIL receivable. PEF recorded a corresponding $154 million addition to its deferred fuel regulatory asset and a $68 million addition to construction work in progress. Negotiations continue with NEIL regarding coverage associated with the second delamination, and PEF continues to believe that all applicable costs associated with bringing CR3 back into service are covered under all insurance policies.

The following table summarizes the CR3 replacement power and repair costs and recovery through December 31, 2011:

(in millions)	Replacement power costs	Repair costs
Spent to date	$ 478	$ 258
NEIL proceeds received	(162)	(136)
Insurance receivable at December 31, 2011, net	(55)	(3)
Balance for recovery[(a)]	$ 261	$ 119

(a) See "2012 Settlement Agreement" and "Fuel Cost Recovery" below for discussion of PEF's ability to recover prudently incurred fuel and purchase power costs and CR3 repair costs.

PEF believes the actions taken and costs incurred in response to the CR3 delamination have been prudent and, accordingly, considers replacement power and capital costs not recoverable through insurance to be recoverable through its fuel cost-recovery clause or base rates. Additional replacement power costs and repair and maintenance costs incurred until CR3 is returned to service could be material. Additionally, we cannot be assured that CR3 can be repaired and brought back to service until full engineering and other analyses are completed.

On October 25, 2010, the FPSC approved PEF's motion to establish a separate spin-off docket to review the prudence and costs related to the outage and replacement fuel and power costs associated with the CR3 extended outage. The FPSC subsequently issued an order dividing the docket into three phases. The first phase will include a prudence review of the events and decisions of PEF leading up to the first delamination event. The second phase will be a consideration of the prudence of PEF's decision to repair or decommission CR3. The third phase of this docket will include the decisions and events subsequent to the first delamination leading up to the March 14, 2011 delamination event and the subsequent repair of the containment building. See "2012 Settlement Agreement – CR3" below for a discussion of the resolution of this docket.

2012 SETTLEMENT AGREEMENT

On February 22, 2012, the FPSC approved a comprehensive settlement agreement between PEF, the Florida Office of Public Counsel and other consumer advocates. The 2012 settlement agreement will continue through the last billing cycle of December 2016. The agreement addresses three principal matters: PEF's proposed Levy Nuclear Power Plant (Levy) Nuclear Project cost recovery, the CR3 delamination prudence review pending before the FPSC, and certain base rate issues. When all of the settlement provisions are factored in, the total increase in 2013 for residential customer bills will be approximately $4.93 per 1,000 kWh, or 4 percent.

Levy

Under the terms of the 2012 settlement agreement, PEF will set the residential cost-recovery factor of PEF's proposed two units at Levy (see "Nuclear Cost Recovery – Levy Nuclear") at $3.45 per 1,000 kWh effective in the first billing cycle of January 2013 and continuing for a five-year period. This amount is intended to recover the estimated retail project costs to date plus costs necessary to obtain the combined license (COL) and any engineering, procurement and construction (EPC) cancellation costs, if PEF ultimately chooses to cancel that contract. PEF will not recover any additional Levy costs from customers through the term of the agreement, or file for any additional recovery before March 1, 2017, unless otherwise agreed to by the parties to the agreement. In addition, the consumer parties will not oppose PEF continuing to pursue a COL for Levy. After the five-year period, PEF will true up any actual costs not recovered under the Levy cost-recovery factor.

The 2012 settlement agreement also provides that PEF will treat the allocated wholesale cost of Levy as a retail regulatory asset and include this asset as a component of rate base and amortization expense for regulatory reporting. PEF will have the discretion to suspend such amortization in full or in part provided that PEF amortizes all of the regulatory asset by December 31, 2016.

CR3

Under the terms of the 2012 settlement agreement, PEF will be permitted to recover prudently incurred fuel and purchased power costs through the fuel clause without regard for the absence of CR3 for the period from the beginning of the CR3 outage through the earlier of the term of the agreement or the return of CR3 to commercial service. If PEF does not begin repairs of CR3 prior to the end of 2012, PEF will refund replacement power costs on a pro rata basis based on the in-service date of up to $40 million in 2015 and $60 million in 2016. The parties to the agreement waive their right to challenge PEF's recovery of these costs. The parties to the agreement maintain the right to challenge the prudence and reasonableness of PEF's fuel acquisition and power purchases, and other fuel prudence issues unrelated to the CR3 outage. All prudence issues from the steam generator project inception through the date of settlement approval by the FPSC are resolved.

To the extent that PEF pursues the repair of CR3, PEF will establish an estimated cost and repair schedule with ongoing consultation with the parties to the agreement. The established cost, to be approved by our board of directors, will be the basis for project measurement. If costs exceed the board-approved estimate, overruns will be split evenly between our shareholders and PEF customers up to $400 million. The parties to the agreement agree to meet to discuss the method of recovery of any overruns in excess of $400 million, with final decision by the FPSC if resolution cannot be reached. If the repairs begin prior to the end of 2012, the parties to the agreement waive their rights to challenge PEF's decision to repair and the repair plan chosen by PEF. In addition, there will be limited rights to challenge recovery of the repair execution costs incurred prior to the final resolution on NEIL coverage. The parties to the agreement will discuss the treatment of any potential gap between NEIL repair coverage and the estimated cost, with final decision by the FPSC if resolution cannot be reached. If the repairs do not begin prior to the end of 2012, the parties to the agreement reserve the right to challenge the prudence of PEF's repair decision, plan and implementation.

PEF also retains sole discretion and flexibility to retire the unit without challenge from the parties to the agreement. If PEF decides to retire CR3, PEF is allowed to recover all remaining CR3 investments and to earn a return on the CR3 investments set at its current authorized overall cost of capital, adjusted to reflect a ROE set at 70 percent of the current FPSC-authorized ROE, no earlier than the first billing cycle of January 2017. Additionally, any NEIL proceeds received after the settlement will be applied first to replacement power costs incurred after December 31, 2012, with the remainder used to write down the remaining CR3 investments.

Base Rates, Customer Refund and Other Terms

Under the terms of the 2012 settlement agreement, PEF will maintain base rates at the current levels through the last billing cycle of December 2016, except as described as follows. The agreement provides for a $150 million annual increase in revenue requirements effective with the first billing cycle of January 2013, while maintaining the current ROE range of 9.5 percent to 11.5 percent. PEF will suspend depreciation expense and reverse certain regulatory liabilities associated with CR3 effective on the implementation date of the agreement. Additionally, rate base associated with CR3 investments will be removed from retail rate base effective with the first billing cycle of

January 2013. PEF will accrue, for future rate-setting purposes a carrying charge at a rate of 7.4 percent on the CR3 investment until CR3 is returned to service and placed back into retail rate base. Upon return of CR3 to commercial service, PEF will be authorized to increase its base rates for the annual revenue requirements of all CR3 investments. The parties to the agreement reserve the right to participate in any hearings challenging the appropriateness of PEF's CR3 revenue requirements. In the month following CR3's return to commercial service, PEF's ROE range will increase to 9.7 percent to 11.7 percent. If PEF's retail base rate earnings fall below the ROE range, as reported on a FPSC-adjusted or pro-forma basis on a PEF monthly earnings surveillance report, PEF may petition the FPSC to amend its base rates during the term of the agreement.

Under the terms of the 2012 settlement agreement, PEF will refund $288 million as of December 31, 2011, to customers through the fuel clause. PEF will refund $129 million in each of 2013 and 2014, and an additional $10 million annually to residential and small commercial customers in 2014, 2015 and 2016. At December 31, 2011, a regulatory liability was established for the $288 million to be refunded in future periods. The corresponding charge was recorded as a reduction of 2011 revenues.

The cost of pollution control equipment that PEF installed and has in-service at CR4 and CR5 to comply with the Federal Clean Air Interstate Rule (CAIR) is currently recovered under the Environmental Cost Recovery Clause (ECRC). The 2012 settlement agreement provides for PEF to remove those assets from recovery in the ECRC and transfer those assets to base rates effective with the first billing cycle of January 2014. The related base rate increase will be in addition to the $150 million base rate increase effective January 2013. O&M expenses associated with those assets will not be included in the base rates and will continue to be recovered through the ECRC.

The 2012 settlement agreement provides for PEF to continue to recover carrying costs and other nuclear cost recovery clause-recoverable items related to the CR3 uprate project, but PEF will not seek an in-service recovery until nine months following CR3's return to commercial service. Carrying costs will be recovered through the nuclear cost recovery clause until base rates have been increased for these assets.

The 2012 settlement agreement also allows PEF to continue to reduce amortization expense (cost of removal component) beyond the expiration of the 2010 settlement agreement through the term of the 2012 settlement agreement. This reduction is limited by the eligible remaining balance of the cost of removal reserve ($246 million at December 31, 2011). Additionally, the 2012 settlement agreement extends PEF's ability to expedite recovery of the cost of named storms and to maintain a storm reserve at its level as of the implementation date of the agreement, and removed the maximum allowed monthly surcharge established by the 2010 settlement agreement.

2010 SETTLEMENT AGREEMENT

On June 1, 2010, the FPSC approved a settlement agreement between PEF and the interveners, with the exception of the Florida Association for Fairness in Ratemaking, to the 2009 rate case. As part of the settlement, PEF withdrew its motion for reconsideration of the rate case order. Among other provisions, under the terms of the settlement agreement, PEF will maintain base rates at current levels through the last billing cycle of 2012. The settlement agreement also provides that PEF will have the discretion to reduce amortization expense (cost of removal component) by up to $150 million in 2010, up to $250 million in 2011, and up to any remaining balance in the cost of removal reserve in 2012 until the earlier of (a) PEF's applicable cost of removal reserve reaches zero, or (b) the expiration of the settlement agreement at the end of 2012. In the event PEF reduces amortization expense by less than the annual amounts for 2010 or 2011, PEF may carry forward (i.e., increase the annual cap by) any unused cost of removal reserve amounts in subsequent years during the term of the agreement. The balance of the cost of removal reserve is impacted by accruals in accordance with PEF's latest depreciation study, removal costs expended and reductions in amortization expense as permitted by the settlement agreement. For the year ended December 31, 2011, PEF recognized a $250 million reduction in amortization expense pursuant to the settlement agreement. PEF had eligible cost of removal reserves of $246 million remaining at December 31, 2011. The settlement agreement also provides PEF with the opportunity to earn a ROE of up to 11.5 percent and provides that if PEF's actual retail base rate earnings fall below a 9.5 percent ROE on an adjusted or pro-forma basis, as reported on a historical 12-month basis during the term of the agreement, PEF may seek general, limited or interim base rate relief, or any combination thereof. Prior to requesting any such relief, PEF must have reflected on its referenced surveillance report associated amortization expense reductions of at least $150 million. The settlement agreement does not preclude PEF from requesting the FPSC to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been or are presently recovered through cost-recovery clauses or surcharges; or (b) that are incremental costs not currently recovered in base rates, which the legislature or FPSC determines are clause recoverable; or (c) which are recoverable through base rates under the nuclear cost-recovery legislation or the FPSC's nuclear cost-recovery rule. PEF also may, at its discretion, accelerate in whole or in part the amortization of certain regulatory assets over the term of the settlement agreement. Finally, PEF will be allowed to recover the costs of named storms on an expedited basis after depletion of the storm damage reserve. Specifically, 60 days following the filing of a cost-recovery petition with the FPSC and based on a 12-month recovery period, PEF can begin recovery, subject to refund, through a surcharge of up to $4.00 per 1,000 kWh on monthly residential customer bills for storm costs. In the event the storm costs exceed that level, any excess additional costs will be deferred and recovered in a subsequent year or years as determined by the FPSC. Additionally, the order approving the settlement agreement allows PEF to use the surcharge to replenish the storm damage reserve to $136 million, the level as of June 1, 2010, after storm costs are fully recovered. At December 31, 2011, PEF's storm damage reserve was $132 million.

On September 14, 2010, the FPSC approved a reduction to PEF's AFUDC rate, from 8.8 percent to 7.4 percent. This new rate is based on PEF's updated authorized ROE and all adjustments approved on January 11, 2010, in PEF's base rate case and will be used for all purposes except for nuclear recoveries with original need petitions submitted on or before December 31, 2010, as permitted by FPSC regulations.

FUEL COST RECOVERY

On November 22, 2011, the FPSC approved an increase of the total fuel-cost recovery by $162 million, increasing the residential rate by $3.32 per 1,000 kWh, or 2.78 percent, effective January 1, 2012. This increase is due to an increase of $3.99 per 1,000 kWh for the projected recovery of fuel costs offset by a decrease of $0.67 per 1,000 kWh for the projected recovery through the Capacity Cost-Recovery Clause (CCRC). The increase in the projected recovery of fuel costs is due to an under-recovery from the prior year. The decrease in the CCRC is primarily due to lower anticipated costs associated with Levy, and the deferral of 2011 and 2012 estimated costs associated with PEF's CR3 uprate project until 2012 (see "Nuclear Cost Recovery"), partially offset by increased capacity costs and a reduction of the refund related to an over-recovery from the prior year. Within the fuel clause, PEF received approval to collect, subject to refund, replacement power costs related to the CR3 nuclear plant outage (See "CR3 Outage" and "2012 Settlement Agreement").

At December 31, 2011, PEF's deferred fuel regulatory liability was $44 million comprised of a $244 million current regulatory asset and a $288 million noncurrent regulatory liability (See "2012 Settlement Agreement"). The current regulatory asset of $244 million includes the $154 million of replacement power costs that were previously recorded as a receivable from NEIL (See "CR3 Outage").

NUCLEAR COST RECOVERY

<u>Levy Nuclear</u>

In 2008, the FPSC granted PEF's petition for an affirmative Determination of Need and related orders requesting cost recovery under Florida's nuclear cost-recovery rule for Levy, together with the associated facilities, including transmission lines and substation facilities. Levy is needed to maintain electric system reliability and integrity, provide fuel and generating diversity, and allow PEF to continue to provide adequate electricity to its customers at a reasonable cost. The proposed Levy units will be advanced passive light water nuclear reactors, each with a generating capacity of approximately 1,100 MW. The petition included projections that Levy Unit No. 1 would be placed in service by June 2016 and Levy Unit No. 2 by June 2017. The filed, nonbinding project cost estimate for Levy Units No. 1 and No. 2 was approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities.

In PEF's 2010 nuclear cost-recovery filing (See "Cost Recovery"), PEF identified a schedule shift in the Levy project that resulted from the NRC's 2009 determination that certain schedule-critical work that PEF had proposed to perform within the scope of its Limited Work Authorization request submitted with the COL application will not be authorized until the NRC issues the COL. Consequently, major construction activities on Levy have been postponed until after the NRC issues the COL for the units, which is expected in 2013 if the current licensing schedule remains on track. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including, but not limited to, cost; potential carbon regulation; fossil fuel prices; the benefits of fuel diversification; public, regulatory and political support; adequate financial cost-recovery mechanisms; appropriate levels of joint owner participation; customer rate impacts; project feasibility; DSM and EE programs; and availability and terms of capital financing. Taking into account these criteria, we consider Levy to be PEF's preferred baseload generation option.

Crystal River Unit No. 3 Nuclear Plant Uprate

In 2007, the FPSC issued an order approving PEF's Determination of Need petition related to a multi-stage uprate of CR3 that will increase CR3's gross output by approximately 180 MW during its next refueling outage. PEF implemented the first-stage design modifications in 2008. The final stage of the uprate required a license amendment to be filed with the NRC, which was filed by PEF in June 2011 and accepted for review by the NRC on November 21, 2011.

Cost Recovery

In 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consisted of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. The FPSC approved the alternate proposal allowing PEF to recover revenue requirements associated with the nuclear cost-recovery clause through the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. In adopting PEF's proposed rate management plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts. The rate management plan included the 2009 reclassification to the nuclear cost-recovery clause regulatory asset of $198 million of capacity revenues and the accelerated amortization of $76 million of preconstruction costs. The cumulative amount of $274 million was recorded as a nuclear cost-recovery regulatory asset at December 31, 2009, and is projected to be recovered by the end of 2014. At December 31, 2011, PEF's nuclear cost-recovery regulatory asset was $102 million, comprised of a $15 million current regulatory liability and a $117 million noncurrent regulatory asset. PEF will continue to recover nuclear costs as provided for by the 2012 settlement agreement.

On October 24, 2011, the FPSC approved a $78 million decrease in the amount charged to PEF's ratepayers for nuclear cost recovery, which is a component of, and is included in, the fuel cost recovery (See "Fuel Cost Recovery"), including recovery of preconstruction and carrying costs and CCRC-recoverable O&M expense anticipated to be incurred during 2012, recovery of $60 million of prior years' deferrals in 2012, as well as the estimated actual true-up of 2011 costs associated with the Levy and CR3 uprate projects. Also included is the stipulation of PEF's filed motion with the FPSC to defer until 2012 the approval of the long-term feasibility analysis of completing the CR3 uprate, and the determination of reasonableness on, and recovery of, 2011 and 2012 estimated costs. This resulted in an estimated decrease in the nuclear cost-recovery charge of $2.67 per 1,000 kWh for residential customers, beginning with the first January 2012 billing cycle.

DEMAND-SIDE MANAGEMENT COST RECOVERY

On July 26, 2011, the FPSC voted to set PEF's DSM compliance goals to remain at their current level until the next goal setting docket is initiated. An intervener filed a protest to the FPSC's Proposed Agency Action order, asserting legal challenges to the order. The parties made legal arguments to the FPSC and the FPSC issued an order denying the protest on December 22, 2011. The intervener then filed a notice of appeal of this order to the Florida Supreme Court on January 17, 2012. We cannot predict the outcome of this matter.

On November 1, 2011, the FPSC approved PEF's request to decrease the Energy Conservation Cost Recovery Clause (ECCR) residential rate by $0.11 per 1,000 kWh, or 0.1 percent of the total residential rate, effective January 1, 2012. The decrease in the ECCR is primarily due to an increased refund of a prior period over-recovery, partially offset by an increase in conservation program costs. At December 31, 2011, PEF's over-recovered deferred ECCR balance was $19 million.

OTHER MATTERS

On November 22, 2011, the FPSC approved PEF's request to increase the ECRC by $24 million, increasing the residential rate by $0.54 per 1,000 kWh, or 0.5 percent, effective January 1, 2012. The increase in the ECRC is primarily due to the 2011 rates including a return of a prior period over-recovery, partially offset by a decrease in the related O&M expense. At December 31, 2011, PEF's over-recovered deferred ECRC was $7 million.

On March 20, 2009, PEF filed a petition with the FPSC for expedited approval of the deferral of $53 million in 2009 pension expense. PEF requested that the deferral of pension expense continue until the recovery of these costs is provided for in FPSC-approved base rates. On June 16, 2009, the FPSC approved the deferral of the retail portion of actual 2009 pension expense. As a result of the order, PEF deferred pension expense of $34 million for the year ended December 31, 2009. PEF will not earn a carrying charge on the deferred pension regulatory asset. The deferral of pension expense did not result in a change in PEF's 2009 retail rates or prices. In accordance with the order, subsequent to 2009 PEF will amortize the deferred pension regulatory asset to the extent that annual pension expense is less than the $27 million allowance provided for in the base rates established in the 2010 base rate proceeding. In the event such amortization is insufficient to fully amortize the regulatory asset, PEF can seek recovery of the remaining unamortized amount in a base rate proceeding no earlier than 2015. As of December 31, 2011, PEF has not recorded any amortization related to the deferred pension regulatory asset. The 2012 settlement agreement allows for accelerated amortization of all or part of this deferred pension regulatory asset.

D. NUCLEAR LICENSE RENEWALS

PEC's nuclear units are currently operating under licenses that expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. PEF applied for a 20-year renewal of the license in 2008. The NRC's remaining open items in the license renewal process are associated with the containment structure repair. Once the repair design has been completed and evaluated, the NRC may proceed with the renewal application review of the containment structure. Assuming the repair is successful, management believes CR3 will satisfy the requirements for the license renewal.

9. GOODWILL

Goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility reporting units and our goodwill impairment tests are performed at the utility reporting unit level. At December 31, 2011 and 2010, our carrying amount of goodwill was $3.655 billion, with $1.922 billion assigned to PEC and $1.733 billion assigned to PEF. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment. We perform our annual impairment test as of October 31 of each year. The results of our 2011 annual test of goodwill indicated that the carrying amounts of goodwill were not impaired.

10. EQUITY

A. COMMON STOCK

PROGRESS ENERGY

At December 31, 2011 and December 31, 2010, we had 500 million shares of common stock authorized under our charter, of which 295 million and 293 million shares were outstanding, respectively. We periodically issue shares of common stock through the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)), the Progress Energy Investor Plus Plan (IPP) and other benefit plans.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2011, there were no significant restrictions on the use of retained earnings (See Note 2 and Note 12B).

The following table presents information for our common stock issuances for the years ended December 31:

	2011		2010		2009	
(in millions)	**Shares**	**Net Proceeds**	Shares	Net Proceeds	Shares	Net Proceeds
Total issuances	**2.0**	**$ 53**	12.2	$ 434	17.5	$ 623
Issuances under an underwritten public offering[(a)]	**-**	**-**	-	-	14.4	523
Issuances through 401(k) and/or IPP	**-**	**1**	11.2	431	2.5	100

(a) The shares issued under an underwritten public offering were issued on January 12, 2009, at a public offering price of $37.50.

PEC

At December 31, 2011 and December 31, 2010, PEC was authorized to issue up to 200 million shares of common stock. All shares issued and outstanding are held by Progress Energy. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2011, there were no significant restrictions on the use of retained earnings. See Note 12B for additional dividend restrictions related to PEC.

PEF

At December 31, 2011 and December 31, 2010, PEF was authorized to issue up to 60 million shares of common stock. All PEF common shares issued and outstanding are indirectly held by Progress Energy. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2011, there were no significant restrictions on the use of retained earnings. See Note 12B for additional dividend restrictions related to PEF.

B. STOCK-BASED COMPENSATION

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. The 401(k), which has a matching feature, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan was held by the 401(k) Trustee in a suspense account. The common stock was released from the suspense account and made available for allocation to participants as the ESOP loan was repaid. Such allocations were used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes. By December 31, 2010, no ESOP suspense shares were outstanding and the ESOP acquisition loan was repaid.

ESOP shares allocated to plan participants totaled 13.4 million at December 31, 2010. Our matching compensation cost under the 401(k) is determined based on matching percentages as defined in the plan. Through December 31, 2010, such compensation cost was allocated to participants' accounts in the form of Progress Energy common stock. Beginning in 2011, such compensation cost was allocated to participants' accounts in the same investments and election percentages as the participants' contributions. In 2010, we met common stock share needs with open market purchases and with shares released from the ESOP suspense account. Matching costs met with shares released from the suspense account totaled $12 million for the years ended December 31, 2010 and 2009, respectively. In 2011, we met common stock share needs with open market purchases.

We also sponsor the Savings Plan for Employees of Florida Progress Corporation, which is an ESOP plan that covers bargaining unit employees of PEF.

Total matching cost for both plans was $44 million, $43 million and $41 million for the years ended December 31, 2011, 2010 and 2009, respectively.

PEC

PEC's matching costs met with shares released from the ESOP suspense account totaled $8 million for the years ended December 31, 2010 and 2009, respectively. Total matching cost was $23 million, $23 million and $22 million for the years ended December 31, 2011, 2010 and 2009, respectively.

PEF

PEF's matching costs met with shares released from the ESOP suspense account totaled $3 million and $4 million for the years ended December 31, 2010 and 2009, respectively. Total matching cost for both plans was $14 million, $14 million and $12 million for the years ended December 31, 2011, 2010 and 2009, respectively.

OTHER STOCK-BASED COMPENSATION PLANS

We have additional compensation plans for our officers and key employees that are stock-based in whole or in part. Our long-term compensation program currently includes two types of equity-based incentives: performance shares under the Performance Share Sub-Plan (PSSP) and restricted stock programs. The compensation program was established pursuant to our 1997 Equity Incentive Plan (EIP) and was continued under our 2002 and 2007 EIPs, as amended and restated from time to time. As authorized by the EIPs, we may grant up to 20 million shares of Progress Energy common stock through our long-term compensation program.

Beginning in 2009, shares issued under the redesigned PSSP use total shareholder return and earnings growth as two equally weighted performance measures. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. We distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. We issue new shares of common stock to satisfy the requirements of the PSSP program. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with subsequent adjustments made to reflect the status of the performance measure. Compensation expense for all awards is reduced by estimated forfeitures. At December 31, 2011, there were an immaterial number of stock-settled performance target shares outstanding. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.

Beginning in 2007, we began issuing restricted stock units (RSUs) rather than the previously issued restricted stock awards for our officers, vice presidents, managers and key employees. RSUs awarded to eligible employees are generally subject to either three- or five-year cliff vesting or three- or five-year graded vesting. We issue new shares of common stock to satisfy the requirements of the RSU program. Compensation expense, based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. RSUs are included as shares outstanding in the basic earnings per share calculation and are converted to shares upon vesting. At December 31, 2011, there were an immaterial number of RSUs outstanding.

The total fair value of RSUs vested during the years ended December 31, 2011, 2010 and 2009, was $24 million, $24 million and $16 million, respectively. No cash was expended to purchase stock to satisfy RSU plan obligations in 2011, 2010 and 2009. The RSUs vested during 2011 had a weighted-average grant date fair value of $39.16.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $33 million for the year ended December 31, 2011, with a recognized tax benefit of $13 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $27 million, with a recognized tax benefit of $11 million, and $37 million, with a recognized tax benefit of $14 million, for the years ended December 31, 2010 and 2009, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2011, unrecognized compensation cost related to nonvested other stock-based compensation plan awards totaled $33 million, which is expected to be recognized over a weighted-average period of 1.6 years.

PEC

PEC's Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $20 million for the year ended December 31, 2011, with a recognized tax benefit of $8 million. The total expense recognized on PEC's Consolidated Statements of Income for other stock-based compensation plans was $16 million, with a recognized tax benefit of $6 million, and $22 million, with a recognized tax benefit of $9 million, for the years ended December 31, 2010 and 2009, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

PEF

PEF's Statements of Income included total recognized expense for other stock-based compensation plans of $13 million for the year ended December 31, 2011, with a recognized tax benefit of $5 million. The total expense recognized on PEF's Statements of Income for other stock-based compensation plans was $11 million, with a recognized tax benefit of $4 million, and $14 million, with a recognized tax benefit of $5 million, for the years ended December 31, 2010 and 2009, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

C. EARNINGS PER COMMON SHARE

Basic earnings per common share are based on the weighted-average number of common shares outstanding, which includes the effects of unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents. Diluted earnings per share include the effects of the nonvested portion of performance share awards and the effect of stock options outstanding.

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

(in millions)	**2011**	2010	2009
Weighted-average common shares – basic	**295.8**	290.7	279.4
Net effect of dilutive stock-based compensation plans	**0.1**	0.1	0.1
Weighted-average shares – fully diluted	**295.9**	290.8	279.5

There were no adjustments to net income or to income from continuing operations attributable to controlling interests between the calculations of basic and fully diluted earnings per common share. There were 0.8 million and 1.5 million stock options outstanding at December 31, 2010 and 2009, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive. As of December 31, 2011, there were no antidilutive stock options outstanding.

D. ACCUMULATED OTHER COMPREHENSIVE LOSS

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

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Cash flow hedges	**$ (143)**	$ (63)	**$ (71)**	$ (33)	**$ (27)**	$ (4)
Pension and other postretirement benefits	**(22)**	(62)	**-**	-	**-**	-
Total accumulated other comprehensive loss	**$ (165)**	$ (125)	**$ (71)**	$ (33)	**$ (27)**	$ (4)

11. PREFERRED STOCK OF SUBSIDIARIES

All of our preferred stock was issued by the Utilities. The preferred stock is considered temporary equity due to certain provisions that could require us to redeem the preferred stock for cash. In the event dividends payable on PEC or PEF preferred stock are in default for an amount equivalent to or exceeding four quarterly dividend payments, the holders of the preferred stock are entitled to elect a majority of PEC's or PEF's respective board of directors until all accrued and unpaid dividends are paid. All classes of preferred stock are entitled to cumulative dividends with preference to the common stock dividends, are redeemable by vote of the Utilities' respective board of directors at any time, and do not have any preemptive rights. All classes of preferred stock have a liquidation preference equal to $100 per share plus any accumulated unpaid dividends except for PEF's 4.75%, $100 par value class, which does not have a liquidation preference. Each holder of PEC's preferred stock is entitled to one vote. The holders of PEF's preferred stock have no right to vote except for certain circumstances involving dividends payable on preferred stock that are in default or certain matters affecting the rights and preferences of the preferred stock.

At December 31, 2011 and 2010, preferred stock outstanding consisted of the following:

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

12. DEBT AND CREDIT FACILITIES

A. DEBT AND CREDIT FACILITIES

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2011):

(in millions)		**2011**	2010
Parent			
Senior unsecured notes, maturing 2012-2039	6.28%	**$ 4,000**	$ 4,200
Unamortized premium and discount, net		**(7)**	(6)
Current portion of long-term debt		**(450)**	(205)
Long-term debt, net		**3,543**	3,989
PEC			
First mortgage bonds, maturing 2013-2038	5.17%	**3,025**	2,525
First mortgage bonds/pollution control obligations, maturing 2017-2024	0.57%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Miscellaneous notes	6.00%	**5**	5
Unamortized premium and discount, net		**(6)**	(6)
Current portion of long-term debt		**(500)**	-
Long-term debt, net		**3,693**	3,693
PEF			
First mortgage bonds, maturing 2013-2040	5.56%	**4,100**	4,100
First mortgage bonds/pollution control obligations, maturing 2018-2027	0.57%	**241**	241
Medium-term notes, maturing 2028	6.75%	**150**	150
Unamortized premium and discount, net		**(9)**	(9)
Current portion of long-term debt		**-**	(300)
Long-term debt, net		**4,482**	4,182
Progress Energy consolidated long-term debt, net		**$ 11,718**	$ 11,864
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**$ 309**	$ 309
Unamortized premium and discount, net		**(36)**	(36)
Long-term debt, affiliate		**$ 273**	$ 273

On January 21, 2011, the Parent issued $500 million of 4.40% Senior Notes due January 15, 2021. The net proceeds of $495 million, along with available cash on hand, were used to retire the $700 million outstanding aggregate principal balance of our 7.10% Senior Notes due March 1, 2011. Accordingly, we classified $495 million of the Parent's $700 million 7.10% Senior Notes due March 1, 2011 as long-term debt at December 31, 2010.

On July 15, 2011, PEF paid at maturity $300 million of its 6.65% First Mortgage Bonds with proceeds from short-term debt.

On August 18, 2011, PEF issued $300 million 3.10% First Mortgage Bonds due August 15, 2021. The net proceeds were used to repay a portion of outstanding short-term debt, of which $300 million was issued to repay PEF's July 15, 2011 maturity.

On September 15, 2011, PEC issued $500 million 3.00% First Mortgage Bonds due September 15, 2021. A portion of the net proceeds was used to repay outstanding short-term debt and the remainder was used for general corporate purposes, including construction expenditures.

On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with a portion of the proceeds from the $950 million of Senior Notes issued on November 19, 2009.

On March 25, 2010, PEF issued $250 million of 4.55% First Mortgage Bonds due April 1, 2020, and $350 million of 5.65% First Mortgage Bonds due April 1, 2040. Proceeds were used to repay the outstanding balance of PEF's notes payable to affiliated companies, to repay the maturity of PEF's $300 million 4.50% First Mortgage Bonds due June 1, 2010, and for general corporate purposes.

At December 31, 2011 and 2010, we had committed lines of credit used to support our commercial paper and other short-term borrowings. At December 31, 2011 and 2010, we had no outstanding borrowings under our revolving credit agreements (RCAs). We are required to pay fees to maintain our credit facilities.

The following tables summarize our RCAs and available capacity at December 31:

(in millions)		**Total**	**Outstanding**	**Reserved[(a)]**	**Available**
2011					
Parent	**Five-year (expiring 5/3/12)[(b)]**	**$ 478**	**$ -**	**$ 252**	**$ 226**
PEC	**Three-year (expiring 10/15/13)**	**750**	**-**	**184**	**566**
PEF	**Three-year (expiring 10/15/13)**	**750**	**-**	**233**	**517**
Total credit facilities		**$ 1,978**	**$ -**	**$ 669**	**$ 1,309**
2010					
Parent	Five-year (expiring 5/3/12)	$ 500	$ -	$ 31	$ 469
PEC	Three-year (expiring 10/15/13)	750	-	-	750
PEF	Three-year (expiring 10/15/13)	750	-	-	750
Total credit facilities		$ 2,000	$ -	$ 31	$ 1,969

(a) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2011 and 2010, the Parent had issued $2 million and $31 million, respectively, of letters of credit supported by the RCA. Additionally, on December 31, 2011, the Parent, PEC and PEF had $250 million, $184 million and $233 million, respectively, of outstanding commercial paper supported by the RCA.

(b) On February 15, 2012, the Parent's RCA was amended to extend its expiration date to May 3, 2013.

The combined RCAs of the Parent, PEC and PEF total $1.978 billion and are supported by 23 financial institutions. The RCAs are used to provide liquidity support for issuances of commercial paper and other short-term obligations, and for general corporate purposes. Fees and interest rates under the RCAs are determined based upon the respective credit ratings of the Parent's, PEC's and PEF's long-term unsecured senior noncredit-enhanced debt, as rated by Moody's Investor Services, Inc. (Moody's) and Standard & Poor's Rating Services (S&P). The RCAs do not include material adverse change representations for borrowings or financial covenants for interest coverage.

The Parent entered into a five-year RCA on May 3, 2006. On May 2, 2008, the expiration date of the RCA was extended to May 3, 2012. The Parent ratably reduced the size of the RCA to $500 million on October 15, 2010, and the RCA was further reduced to $478 million on May 3, 2011, following the expiration of one financial institution's credit commitment. On February 15, 2012, the Parent's $478 million RCA was amended to extend the expiration date from May 3, 2012, to May 3, 2013, with its existing syndicate of 14 financial institutions.

PEC and PEF entered into $750 million, three-year RCAs with a syndication of 22 financial institutions on October 15, 2010. The RCAs, which expire October 15, 2013, replaced PEC's and PEF's previous RCAs, which were set to expire on June 28, 2011, and March 28, 2011, respectively.

See "Covenants and Default Provisions" for additional provisions related to the RCAs.

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

(in millions)	**2011**		2010	
Parent	**0.50%**	**$ 250**	-%	$ -
PEC	**0.49**	**188**	-	-
PEF	**0.51**	**233**	-	-
Total	**0.50%**	**$ 671**	-%	$ -

Long-term debt maturities during the next five years are as follows:

(in millions)	Progress Energy Consolidated	PEC	PEF
2012	$ 950	$ 500	$ -
2013	830	405	425
2014	300	-	-
2015	1,000	700	300
2016	300	-	-

B. COVENANTS AND DEFAULT PROVISIONS

FINANCIAL COVENANTS

The Parent's, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capitalization ratio (leverage). At December 31, 2011, the maximum and calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[a]
Parent	68%	58%
PEC	65%	46%
PEF	65%	51%

[a] Indebtedness as defined by the credit agreement includes certain letters of credit, surety bonds and guarantees not recorded on the Consolidated Balance Sheets.

CROSS-DEFAULT PROVISIONS

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

Additionally, certain of the Parent's long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of the Parent, primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $4.000 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither the Parent's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. At December 31, 2011, the Parent had no shares of preferred stock outstanding. See Note 2 for information regarding restrictions on dividends relative to the Progress Energy and Duke Energy Agreement and Plan of Merger.

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

PEC

PEC's mortgage indenture provides that as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million, less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2011, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, as defined by PEC's Articles of Incorporation, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2011, PEC's common stock equity was approximately 57.6 percent of total capitalization. At December 31, 2011, none of PEC's cash dividends or distributions on common stock was restricted.

PEF

PEF's mortgage indenture provides that as long as any first mortgage bonds are outstanding, it will not pay any cash dividends upon its common stock, or make any other distribution to the stockholders, except a payment or distribution out of net income of PEF subsequent to December 31, 1943. At December 31, 2011, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, as defined by PEF's Articles of Incorporation, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2011, PEF's common stock equity was approximately 50.9 percent of total capitalization. At December 31, 2011, none of PEF's cash dividends or distributions on common stock was restricted.

C. COLLATERALIZED OBLIGATIONS

PEC's and PEF's first mortgage bonds, including pollution control obligations, 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, 2011, PEC and PEF had a total of $3.694 billion and $4.341 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations.

Each mortgage allows the issuance of additional first mortgage bonds based on property additions, retirements of first mortgage bonds and the deposit of cash if certain conditions are satisfied. Most first mortgage bond issuances by PEC and PEF require that adjusted net earnings be at least twice the annual interest requirement for bonds currently outstanding and to be outstanding. PEF's ratio of net earnings to the annual interest requirement for bonds outstanding was below 2.0 times at December 31, 2011. PEF's 2011 net earnings were impacted by a $288 million charge recorded in December 2011 for amounts to be refunded to customers (See Note 8C). Until this ratio, which is calculated based on results for 12 consecutive months, is above 2.0 times, PEF's capacity to issue first mortgage bonds is limited to a portion of retired first mortgage bonds. In the event PEF's long-term debt requirements exceed its first mortgage bond capacity, it could issue unsecured debt.

D. GUARANTEES OF SUBSIDIARY DEBT

See Note 19 on related party transactions for a discussion of obligations guaranteed or secured by affiliates.

E. HEDGING ACTIVITIES

We use interest rate derivatives to adjust the fixed and variable rate components of our debt portfolio and to hedge cash flow risk related to commercial paper and fixed-rate debt to be issued in the future. See Note 18 for a discussion of risk management activities and derivative transactions.

13. INVESTMENTS

A. INVESTMENTS

At December 31, 2011 and 2010, we had investments in various debt and equity securities, cost investments, company-owned life insurance and investments held in trust funds as follows:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Nuclear decommissioning trust (See Notes 5C and 14)	**$ 1,647**	$ 1,571	**$ 1,088**	$ 1,017	**$ 559**	$ 554
Equity method investments[(a)]	**14**	16	**1**	3	**2**	2
Cost investments[(b)]	**2**	5	**2**	4	**-**	-
Company-owned life insurance[(c)]	**47**	46	**39**	37	**-**	-
Benefit investment trusts[(d)]	**176**	175	**105**	97	**37**	37
Total	**$ 1,886**	$ 1,813	**$ 1,235**	$ 1,158	**$ 598**	$ 593

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

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

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

(d) Benefit investment trusts are included in miscellaneous other property and investments on the Consolidated Balance Sheets. At December 31, 2011 and 2010, $173 million and $166 million, respectively, of investments in company-owned life insurance were held in Progress Energy's trusts. Substantially all of PEC's and PEF's benefit investment trusts are invested in company-owned life insurance.

B. IMPAIRMENT OF INVESTMENTS

Declines in fair value of available-for-sale securities to below the cost basis that are judged to be other than temporary are included in long-term regulatory assets or liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the Consolidated Statements of Income for securities in our benefit investment trusts, other available-for-sale securities and equity and cost method investments. See Note 14 for additional information. There were no material other-than-temporary impairments recognized in earnings in 2011, 2010 or 2009.

14. FAIR VALUE DISCLOSURES

A. DEBT AND INVESTMENTS

PROGRESS ENERGY

DEBT

The carrying amount of our long-term debt, including current maturities, was $12.941 billion and $12.642 billion at December 31, 2011 and 2010, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $15.3 billion and $14.0 billion at December 31, 2011 and 2010, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. Our available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning the Utilities' nuclear plants (See Note 5C). NDT funds are presented on the Consolidated Balance Sheets at fair value. In addition to the NDT funds, we hold other debt investments classified as available-for-sale, which are included in miscellaneous other property and investments on the Consolidated Balance Sheets at fair value.

The following table summarizes our available-for-sale securities at December 31:

(in millions)	Fair Value	Unrealized Losses	Unrealized Gains
2011			
Common stock equity	**$ 1,033**	**$ 29**	**$ 401**
Preferred stock and other equity	**29**	**-**	**11**
Corporate debt	**86**	**-**	**6**
U.S. state and municipal debt	**128**	**2**	**7**
U.S. and foreign government debt	**284**	**-**	**18**
Money market funds and other	**70**	**-**	**1**
Total	**$ 1,630**	**$ 31**	**$ 444**
2010			
Common stock equity	$ 1,021	$ 13	$ 408
Preferred stock and other equity	28	-	11
Corporate debt	90	-	6
U.S. state and municipal debt	132	4	3
U.S. and foreign government debt	264	2	10
Money market funds and other	52	-	1
Total	$ 1,587	$ 19	$ 439

The NDT funds and other available-for-sale debt investments held in certain benefit trusts are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and unrealized gains for 2011 and 2010 relate to the NDT funds. There were no material unrealized losses and unrealized gains for the other available-for-sale debt securities held in benefit trusts at December 31, 2011 and 2010.

The aggregate fair value of investments that related to the December 31, 2011 and 2010 unrealized losses was $136 million and $195 million, respectively.

At December 31, 2011, the fair value of our available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 44
Due after one through five years	231
Due after five through 10 years	147
Due after 10 years	90
Total	$ 512

The following table presents selected information about our sales of available-for-sale securities for the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2011**	2010	2009
Proceeds	**$ 4,640**	$ 6,747	$ 2,207
Realized gains	**30**	21	26
Realized losses	**33**	27	87

Proceeds were primarily related to NDT funds. Realized gains and losses for investments in the benefit investment trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary. At December 31, 2011 and 2010, our other securities had no investments in a continuous loss position for greater than 12 months.

PEC

DEBT

The carrying amount of PEC's long-term debt, including current maturities, was $4.193 billion and $3.693 billion at December 31, 2011 and 2010, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $4.7 billion and $4.0 billion at December 31, 2011 and 2010, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. PEC's available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning PEC's nuclear plants (See Note 5C). NDT funds are presented on the Consolidated Balance Sheets at fair value.

The following table summarizes PEC's available-for-sale securities at December 31:

(in millions)	Fair Value	Unrealized Losses	Unrealized Gains
2011			
Common stock equity	**$ 673**	**$ 20**	**$ 255**
Preferred stock and other equity	**17**	**-**	**7**
Corporate debt	**69**	**-**	**5**
U.S. state and municipal debt	**56**	**-**	**3**
U.S. and foreign government debt	**226**	**-**	**16**
Money market funds and other	**60**	**-**	**1**
Total	**$ 1,101**	**$ 20**	**$ 287**
2010			
Common stock equity	$ 652	$ 10	$ 256
Preferred stock and other equity	14	-	6
Corporate debt	72	-	5
U.S. state and municipal debt	51	1	1
U.S. and foreign government debt	199	1	9
Money market funds and other	42	-	1
Total	$ 1,030	$ 12	$ 278

The NDT funds are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and gains for 2011 and 2010 relate to the NDT funds.

The aggregate fair value of investments that related to the December 31, 2011 and 2010 unrealized losses was $98 million and $104 million, respectively.

At December 31, 2011, the fair value of PEC's available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 16
Due after one through five years	184
Due after five through 10 years	100
Due after 10 years	62
Total	$ 362

The following table presents selected information about PEC's sales of available-for-sale securities for the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2011**	2010	2009
Proceeds	**$ 496**	$ 419	$ 622
Realized gains	**13**	10	9
Realized losses	**16**	19	36

PEC's proceeds were primarily related to NDT funds. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary. At December 31, 2011 and 2010, PEC did not have any other securities.

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $4.482 billion at December 31, 2011 and 2010. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $5.4 billion and $5.0 billion at December 31, 2011 and 2010, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. PEF's available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning PEF's nuclear plant (See Note 5C). The NDT funds are presented on the Balance Sheets at fair value.

The following table summarizes PEF's available-for-sale securities at December 31:

(in millions)	**Fair Value**	**Unrealized Losses**	**Unrealized Gains**
2011			
Common stock equity	**$ 360**	**$ 9**	**$ 146**
Preferred stock and other equity	**12**	**-**	**4**
Corporate debt	**17**	**-**	**1**
U.S. state and municipal debt	**72**	**2**	**4**
U.S. and foreign government debt	**58**	**-**	**2**
Money market funds and other	**10**	**-**	**-**
Total	**$ 529**	**$ 11**	**$ 157**
2010			
Common stock equity	$ 369	$ 3	$ 152
Preferred stock and other equity	14	-	5
Corporate debt	14	-	1
U.S. state and municipal debt	81	3	2
U.S. and foreign government debt	62	1	1
Money market funds and other	10	-	-
Total	$ 550	$ 7	$ 161

The NDT funds are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities pursuant to ratemaking treatment. Therefore, the preceding tables include unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and gains for 2011 and 2010 relate to the NDT funds.

The aggregate fair value of investments that related to the December 31, 2011 and 2010 unrealized losses was $38 million and $87 million, respectively.

At December 31, 2011, the fair value of PEF's available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 28
Due after one through five years	47
Due after five through 10 years	47
Due after 10 years	28
Total	$ 150

The following table presents selected information about PEF's sales of available-for-sale securities for the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2011**	2010	2009
Proceeds	**$ 4,130**	$ 6,170	$ 1,471
Realized gains	**17**	10	14
Realized losses	**17**	8	50

PEF's proceeds were related to NDT funds. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary. At December 31, 2011 and 2010, PEF did not have any other securities.

B. FAIR VALUE MEASUREMENTS

GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Fair value measurements require the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs. A midmarket pricing convention (the midpoint price between bid and ask prices) is permitted for use as a practical expedient.

GAAP also establishes a fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

Level 1 – The pricing inputs are unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities.

Level 2 – The pricing inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 2 includes financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives, such as over-the-counter forwards, swaps and options; certain marketable debt securities; and financial instruments traded in less than active markets.

Level 3 – The pricing inputs include significant inputs generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments may include longer-term instruments that extend into periods in which quoted prices or other observable inputs are not available.

Certain assets and liabilities, including long-lived assets, were measured at fair value on a nonrecurring basis. There were no significant fair value measurement losses recognized for such assets and liabilities in the periods reported. These fair value measurements fall within Level 3 of the hierarchy discussed above.

The following tables set forth, by level within the fair value hierarchy, our and the Utilities' financial assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. Financial assets and liabilities are classified in their entirety based on the lowest level of input significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

PROGRESS ENERGY

(in millions)	Level 1	Level 2	Level 3	Total
2011				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	**$ 1,033**	**$ -**	**$ -**	**$ 1,033**
Preferred stock and other equity	**28**	**1**	**-**	**29**
Corporate debt	**-**	**86**	**-**	**86**
U.S. state and municipal debt	**-**	**128**	**-**	**128**
U.S. and foreign government debt	**87**	**197**	**-**	**284**
Money market funds and other	**-**	**87**	**-**	**87**
Total nuclear decommissioning trust funds	**1,148**	**499**	**-**	**1,647**
Derivatives				
Commodity forward contracts	**-**	**5**	**-**	**5**
Other marketable securities				
Money market and other	**20**	**-**	**-**	**20**
Total assets	**$ 1,168**	**$ 504**	**$ -**	**$ 1,672**
Liabilities				
Derivatives				
Commodity forward contracts	**$ -**	**$ 668**	**$ 24**	**$ 692**
Interest rate contracts	**-**	**93**	**-**	**93**
Contingent value obligations	**-**	**14**	**-**	**14**
Total liabilities	**$ -**	**$ 775**	**$ 24**	**$ 799**

(in millions)	Level 1	Level 2	Level 3	Total
2010				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 1,021	$ -	$ -	$ 1,021
Preferred stock and other equity	22	6	-	28
Corporate debt	-	86	-	86
U.S. state and municipal debt	-	132	-	132
U.S. and foreign government debt	79	182	-	261
Money market funds and other	1	42	-	43
Total nuclear decommissioning trust funds	1,123	448	-	1,571
Derivatives				
Commodity forward contracts	-	15	-	15
Interest rate contracts	-	4	-	4
Other marketable securities				
Corporate debt	-	4	-	4
U.S. and foreign government debt	-	3	-	3
Money market and other	18	-	-	18
Total assets	$ 1,141	$ 474	$ -	$ 1,615
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 458	$ 36	$ 494
Interest rate contracts	-	39	-	39
Contingent value obligations	-	15	-	15
Total liabilities	$ -	$ 512	$ 36	$ 548

PEC

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	**$ 673**	**$ -**	**$ -**	**$ 673**
Preferred stock and other equity	**17**	**-**	**-**	**17**
Corporate debt	**-**	**69**	**-**	**69**
U.S. state and municipal debt	**-**	**56**	**-**	**56**
U.S. and foreign government debt	**81**	**145**	**-**	**226**
Money market funds and other	**-**	**47**	**-**	**47**
Total nuclear decommissioning trust funds	**771**	**317**	**-**	**1,088**
Other marketable securities	**6**	**-**	**-**	**6**
Total assets	**$ 777**	**$ 317**	**$ -**	**$ 1,094**
Liabilities				
Derivatives				
Commodity forward contracts	**$ -**	**$ 177**	**$ 24**	**$ 201**
Interest rate contracts	**-**	**47**	**-**	**47**
Total liabilities	**$ -**	**$ 224**	**$ 24**	**$ 248**

(in millions)		Level 1		Level 2		Level 3		Total
2010								
Assets								
Nuclear decommissioning trust funds								
Common stock equity	$	652	$	-	$	-	$	652
Preferred stock and other equity		14		-		-		14
Corporate debt		-		72		-		72
U.S. state and municipal debt		-		51		-		51
U.S. and foreign government debt		76		123		-		199
Money market funds and other		1		28		-		29
Total nuclear decommissioning trust funds		743		274		-		1,017
Derivatives								
Commodity forward contracts		-		2		-		2
Interest rate contracts		-		3		-		3
Other marketable securities		4		-		-		4
Total assets	$	747	$	279	$	-	$	1,026
Liabilities								
Derivatives								
Commodity forward contracts	$	-	$	87	$	36	$	123
Interest rate contracts		-		11		-		11
Total liabilities	$	-	$	98	$	36	$	134

PEF

(in millions)		**Level 1**		**Level 2**		**Level 3**		**Total**
2011								
Assets								
Nuclear decommissioning trust funds								
Common stock equity	**$**	**360**	**$**	**-**	**$**	**-**	**$**	**360**
Preferred stock and other equity		**11**		**1**		**-**		**12**
Corporate debt		**-**		**17**		**-**		**17**
U.S. state and municipal debt		**-**		**72**		**-**		**72**
U.S. and foreign government debt		**6**		**52**		**-**		**58**
Money market funds and other		**-**		**40**		**-**		**40**
Total nuclear decommissioning trust funds		**377**		**182**		**-**		**559**
Derivatives								
Commodity forward contracts		**-**		**5**		**-**		**5**
Other marketable securities		**1**		**-**		**-**		**1**
Total assets	**$**	**378**	**$**	**187**	**$**	**-**	**$**	**565**
Liabilities								
Derivatives								
Commodity forward contracts	**$**	**-**	**$**	**491**	**$**	**-**	**$**	**491**
Interest rate contracts		**-**		**8**		**-**		**8**
Total liabilities	**$**	**-**	**$**	**499**	**$**	**-**	**$**	**499**

(in millions)	Level 1	Level 2	Level 3	Total
2010				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 369	$ -	$ -	$ 369
Preferred stock and other equity	8	6	-	14
Corporate debt	-	14	-	14
U.S. state and municipal debt	-	81	-	81
U.S. and foreign government debt	3	59	-	62
Money market funds and other	-	14	-	14
Total nuclear decommissioning trust funds	380	174	-	554
Derivatives				
Commodity forward contracts	-	13	-	13
Other marketable securities	1	-	-	1
Total assets	$ 381	$ 187	$ -	$ 568
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 371	$ -	$ 371
Interest rate contracts	-	7	-	7
Total liabilities	$ -	$ 378	$ -	$ 378

The determination of the fair values in the preceding tables incorporates various factors, including risks of nonperformance by us or our counterparties. Such risks consider not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits or letters of credit), but also the impact of our and the Utilities' credit risk on our liabilities.

Commodity forward contract derivatives and interest rate contract derivatives reflect positions held by us and the Utilities. Most over-the-counter commodity forward contract derivatives and interest rate contract derivatives are valued using financial models which utilize observable inputs for similar instruments and are classified within Level 2. Other derivatives are valued utilizing inputs that are not observable for substantially the full term of the contract, or for which the impact of the unobservable period is significant to the fair value of the derivative. Such derivatives are classified within Level 3. See Note 18 for discussion of risk management activities and derivative transactions.

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

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

Contingent Value Obligations (CVOs), which are derivatives, are discussed further in Note 16. At September 30, 2011, we determined the fair value of the CVOs based on the purchase price in a negotiated settlement agreement (a Level 3 input) and classified CVOs as Level 3 at that date. Prior to September 30, 2011, the CVOs were recorded at fair value based on observable prices from a less-than-active market and classified as Level 2. In November 2011, we commenced a public tender offer that expired on February 15, 2012. All CVOs not tendered as of December 31, 2011, were classified as Level 2 based on observable prices in the less-than-active market.

Transfers in (out) of Levels 1, 2 or 3 represent existing assets or liabilities previously categorized as a higher level for which the inputs to the estimate became less observable or assets and liabilities that were previously classified as Level 2 or 3 for which the lowest significant input became more observable during the period. There were no significant transfers in (out) of Levels 1, 2 and 3 during the period other than the CVO transfer previously discussed. Transfers into and out of each level are measured at the end of the period.

A reconciliation of changes in the fair value of our and the Utilities' derivatives, net classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

PROGRESS ENERGY

(in millions)	**2011**	2010	2009
Derivatives, net at beginning of period	**$ 36**	$ 39	$ 41
Total losses (gains), realized and unrealized – commodities deferred as regulatory assets and liabilities, net	**21**	44	13
Repurchases of CVOs under settlement and tender offer	**(60)**	-	-
Transfers into Level 3 – CVOs	**74**	-	-
Transfers out of Level 3 – CVOs	**(14)**	-	-
Transfers in (out) of Level 3, net – commodities	**(33)**	(47)	(15)
Derivatives, net at end of period	**$ 24**	$ 36	$ 39

PEC

(in millions)	**2011**	2010	2009
Derivatives, net at beginning of period	**$ 36**	$ 27	$ 22
Total losses (gains), realized and unrealized – commodities deferred as regulatory assets and liabilities, net	**20**	27	7
Transfers in (out) of Level 3, net – commodities	**(32)**	(18)	(2)
Derivatives, net at end of period	**$ 24**	$ 36	$ 27

PEF

(in millions)	**2011**	2010	2009
Derivatives, net at beginning of period	**$ -**	$ 12	$ 19
Total losses (gains), realized and unrealized – commodities deferred as regulatory assets and liabilities, net	**1**	17	6
Transfers in (out) of Level 3, net – commodities	**(1)**	(29)	(13)
Derivatives, net at end of period	**$ -**	$ -	$ 12

Substantially all unrealized gains and losses on the Utilities' derivatives are deferred as regulatory liabilities or assets consistent with ratemaking treatment. Realized and unrealized losses on the change in fair value of our CVOs are discussed in Note 18.

15. INCOME TAXES

We provide deferred income taxes for temporary 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 is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to GAAP for regulated operations. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount that, in our judgment, is greater than 50 percent likely to be realized.

PROGRESS ENERGY

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

(in millions)	**2011**	2010
Deferred income tax assets		
Derivative instruments	**$ 309**	$ 204
Income taxes refundable through future rates	**375**	271
Pension and other postretirement benefits	**591**	447
Other	**522**	501
Tax credit carry forwards	**872**	839
Net operating loss carry forwards	**291**	105
Valuation allowance	**(71)**	(60)
Total deferred income tax assets	**2,889**	2,307
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(3,098)**	(2,439)
Income taxes recoverable through future rates	**(1,271)**	(875)
Other	**(303)**	(386)
Total deferred income tax liabilities	**(4,672)**	(3,700)
Total net deferred income tax liabilities	**$ (1,783)**	$ (1,393)

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

(in millions)	**2011**	2010
Current deferred income tax assets, included in deferred tax assets	**$ 371**	$ 156
Noncurrent deferred income tax assets, included in other assets and deferred debits	**27**	34
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(2,181)**	(1,583)
Total net deferred income tax liabilities	**$ (1,783)**	$ (1,393)

At December 31, 2011, we had the following tax credit and net operating loss carry forwards:

- $868 million of federal alternative minimum tax credits that do not expire.
- $4 million of federal general business credits that will expire during the period 2028 through 2031.
- $623 million of gross federal net operating loss carry forwards that will expire during 2031. $14 million of the gross federal net operating loss carry forward is related to excess tax deductions resulting from stock-based compensation plans. The tax benefit from the utilization of this portion of the federal net operating loss carry forward will be recorded as a credit to common stock when realized.
- $1.9 billion of gross state net operating loss carry forwards that will expire during the period 2012 through 2031.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We had a net increase of $11 million in our deferred income tax assets and valuation allowances during 2011 related to prior year state net operating loss carry forwards at Progress Fuels Corporation.

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

Certain substantial changes in ownership of Progress Energy, including the proposed merger between Progress Energy and Duke Energy (See Note 2), can impact the timing of the utilization of tax credit carry forwards and net operating loss carry forwards.

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

	2011	2010	2009
Effective income tax rate	**35.6%**	38.3%	32.1%
State income taxes, net of federal benefit	**(4.3)**	(4.3)	(3.7)
Investment tax credit amortization	**0.8**	0.5	0.8
Employee stock ownership plan dividends	**1.4**	0.9	1.0
Domestic manufacturing deduction	**-**	-	0.8
AFUDC equity	**2.6**	1.4	2.2
Other differences, net	**(1.1)**	(1.8)	1.8
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

(in millions)	**2011**	2010	2009
Current			
Federal	**$ (91)**	$ (46)	$ 227
State	**29**	(13)	41
Total current income tax expense (benefit)	**(62)**	(59)	268
Deferred			
Federal	**578**	542	114
State	**27**	100	25
Total deferred income tax expense	**605**	642	139
Investment tax credit	**(7)**	(7)	(10)
Net operating loss carry forward	**(213)**	(37)	-
Total income tax expense	**$ 323**	$ 539	$ 397

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

- Taxes related to discontinued operations recorded net of tax for 2011, 2010 and 2009, which are presented separately in Note 4A.
- Taxes related to other comprehensive income recorded net of tax for 2011, 2010 and 2009, which are presented separately on the Consolidated Statements of Comprehensive Income.
- An immaterial amount of current tax benefit, which was recorded in common stock during 2010, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2011 and 2009.

At December 31, 2011, 2010 and 2009, our liability for unrecognized tax benefits was $173 million, $176 million and $160 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $6 million, $8 million and $9 million at December 31, 2011, 2010 and 2009, respectively. The following table presents the changes to unrecognized tax benefits during the years ended December 31:

(in millions)	**2011**	2010	2009
Unrecognized tax benefits at beginning of period	**$ 176**	$ 160	$ 104
Gross amounts of increases as a result of tax positions taken in a prior period	**88**	10	11
Gross amounts of decreases as a result of tax positions taken in a prior period	**(24)**	(4)	(3)
Gross amounts of increases as a result of tax positions taken in the current period	**9**	14	52
Gross amounts of decreases as a result of tax positions taken in the current period	**(8)**	(4)	(4)
Amounts of net decreases relating to settlements with taxing authorities	**(68)**	-	-
Unrecognized tax benefits at end of period	**$ 173**	$ 176	$ 160

We and our subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Our federal tax years are open for examination from 2007 forward, and our open state tax years in our major jurisdictions generally are from 2003 forward. In 2011, the IRS completed its examination of the 2004 and 2005 tax years. It is reasonably possible that unrecognized tax benefits will decrease by approximately $25 million during the 12-month period ending December 31, 2012, due to IRS review of open tax years. Any potential decrease will not have a material impact on our results of operations.

We include interest expense related to unrecognized tax benefits in net interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2011, 2010 and 2009, the net interest (benefit) expense related to unrecognized tax benefits was $(24) million, $9 million and $9 million, respectively, of which a respective $(22) million, $5 million and $5 million (benefit) expense component was deferred as a regulatory asset by PEF, which is amortized as a charge to interest expense over a three-year period or less. During 2011, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2011, 2010 and 2009, there were no penalties related to unrecognized tax benefits. At December 31, 2011, 2010 and 2009, we accrued $21 million, $45 million and $36 million, respectively, for interest and penalties, which were included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

PEC

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

(in millions)	**2011**	2010
Deferred income tax assets		
ARO liability	**$ 101**	$ 103
Derivative instruments	**96**	49
Income taxes refundable through future rates	**142**	142
Pension and other postretirement benefits	**244**	180
Other	**168**	158
Tax credit carry forwards	**3**	-
Net operating loss carry forwards	**54**	-
Total deferred income tax assets	**808**	632
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,908)**	(1,552)
Income taxes recoverable through future rates	**(541)**	(421)
Investments	**(103)**	(104)
Other	**(17)**	(35)
Total deferred income tax liabilities	**(2,569)**	(2,112)
Total net deferred income tax liabilities	**$ (1,761)**	$ (1,480)

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

(in millions)	**2011**	2010
Current deferred income tax assets, included in deferred tax assets	**$ 142**	$ 65
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(1,903)**	(1,545)
Total net deferred income tax liabilities	**$ (1,761)**	$ (1,480)

At December 31, 2011, PEC had the following tax credit and net operating loss carry forwards:

- $3 million of federal general business credits that will expire during the period 2028 through 2031.
- $161 million of gross federal net operating loss carry forwards that will expire during 2031. $6 million of the gross federal net operating loss carry forward is related to excess tax deductions resulting from stock-based compensation plans. The tax benefit from the utilization of this portion of the federal net operating loss carry forward will be recorded as a credit to common stock when realized.
- $1 million of gross state net operating loss carry forwards that will expire during the period 2012 through 2030.

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

	2011	2010	2009
Effective income tax rate	**33.2%**	36.8%	35.0%
State income taxes, net of federal benefit	**(2.3)**	(3.2)	(2.8)
Investment tax credit amortization	**0.7**	0.6	0.7
Domestic manufacturing deduction	**-**	0.4	0.9
AFUDC equity	**2.2**	1.5	0.6
Other differences, net	**1.2**	(1.1)	0.6
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense for the years ended December 31 was comprised of:

(in millions)	**2011**	2010	2009
Current			
Federal	**$ (27)**	$ 73	$ 192
State	**21**	(8)	21
Total current income tax expense (benefit)	**(6)**	65	213
Deferred			
Federal	**316**	238	57
State	**6**	53	13
Total deferred income tax expense	**322**	291	70
Investment tax credit	**(6)**	(6)	(6)
Net operating loss carry forward	**(54)**	-	-
Total income tax expense	**$ 256**	$ 350	$ 277

Total income tax expense excluded taxes related to other comprehensive income recorded net of tax for 2011, 2010 and 2009, which are presented separately on the Consolidated Statements of Comprehensive Income.

PEC and each of its wholly owned subsidiaries have entered into the Tax Agreement with the Parent (See Note 1D). PEC's intercompany tax receivable was approximately $4 million and $78 million at December 31, 2011 and 2010, respectively.

At December 31, 2011, 2010 and 2009, PEC's liability for unrecognized tax benefits was $73 million, $74 million and $59 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $1 million, $4 million and $5 million at December 31, 2011, 2010 and 2009, respectively. The following table presents the changes to unrecognized tax benefits during the years ended December 31:

(in millions)	**2011**	2010	2009
Unrecognized tax benefits at beginning of period	**$ 74**	$ 59	$ 38
Gross amounts of increases as a result of tax positions taken in a prior period	**19**	8	6
Gross amounts of decreases as a result of tax positions taken in a prior period	**(14)**	(2)	(2)
Gross amounts of increases as a result of tax positions taken in the current period	**8**	10	17
Gross amounts of decreases as a result of tax positions taken in the current period	**(4)**	(1)	-
Amounts of net decreases relating to settlements with taxing authorities	**(10)**	-	-
Unrecognized tax benefits at end of period	**$ 73**	$ 74	$ 59

We file consolidated federal and state income tax returns that include PEC. In addition, PEC files stand-alone tax returns in various state jurisdictions. PEC's open federal tax years are from 2007 forward, and PEC's open state tax years in our major jurisdictions generally are from 2003 forward. In 2011, the IRS completed its examination of the 2004 and 2005 tax years. PEC is not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2012.

PEC includes interest expense related to unrecognized tax benefits in net interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2011, 2010 and 2009, the interest (benefit) expense recorded related to unrecognized tax benefits was $(6) million, $4 million and $3 million, respectively. During 2011, 2010 and 2009, there were no penalties related to unrecognized tax benefits. At December 31, 2011, 2010 and 2009, we accrued $8 million, $14 million and $10 million, respectively, for interest and penalties, which were included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

PEF

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

(in millions)	**2011**	2010
Deferred income tax assets		
Derivative instruments	**$ 198**	$ 145
Income taxes refundable through future rates	**198**	93
Pension and other postretirement benefits	**224**	170
Reserve for storm damage	**52**	52
Unbilled revenue	**39**	61
Other	**101**	82
Tax credit carry forwards	**1**	3
Net operating loss carry forwards	**41**	9
Total deferred income tax assets	**854**	615
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,180)**	(874)
Deferred fuel recovery	**(40)**	(65)
Deferred nuclear cost recovery	**(68)**	(94)
Income taxes recoverable through future rates	**(685)**	(454)
Investments	**(56)**	(60)
Other	**(12)**	(18)
Total deferred income tax liabilities	**(2,041)**	(1,565)
Total net deferred income tax liabilities	**$ (1,187)**	$ (950)

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

(in millions)	**2011**	2010
Current deferred income tax assets, included in deferred tax assets	**$ 138**	$ 77
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(1,325)**	(1,027)
Total net deferred income tax liabilities	**$ (1,187)**	$ (950)

At December 31, 2011, PEF had the following tax credit and net operating loss carry forwards:

- $1 million of federal general business credits that will expire during the period 2029 through 2031.
- $120 million of gross federal net operating loss carry forwards that will expire during 2031. $3 million of the gross federal net operating loss carry forward is related to excess tax deductions resulting from stock-based compensation plans. The tax benefit from the utilization of this portion of the federal net operating loss carry forward will be recorded as a credit to common stock when realized.

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

	2011	2010	2009
Effective income tax rate	**36.3%**	37.9%	31.1%
State income taxes, net of federal benefit	**(3.5)**	(3.2)	(3.0)
Investment tax credit amortization	**0.3**	0.2	0.7
Domestic manufacturing deduction	**-**	-	0.8
AFUDC equity	**1.4**	0.8	3.4
Other differences, net	**0.5**	(0.7)	2.0
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense for the years ended December 31 was comprised of:

(in millions)	**2011**	2010	2009
Current			
Federal	**$ (60)**	$ (44)	$ 125
State	**5**	(4)	20
Total current income tax expense (benefit)	**(55)**	(48)	145
Deferred			
Federal	**255**	293	57
State	**22**	41	11
Total deferred income tax expense	**277**	334	68
Investment tax credit	**(1)**	(1)	(4)
Net operating loss carry forward	**(41)**	(9)	-
Total income tax expense	**$ 180**	$ 276	$ 209

Total income tax expense excluded the following:

- Taxes related to other comprehensive income recorded net of tax for 2011, 2010 and 2009, which are presented separately on the Statements of Comprehensive Income.
- An immaterial amount of current tax benefit, which was recorded in common stock during 2010, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2011 and 2009.

PEF has entered into the Tax Agreement with the Parent (See Note 1D). PEF's intercompany tax receivable was approximately $23 million and $71 million at December 31, 2011 and 2010, respectively.

At December 31, 2011, 2010 and 2009, PEF's liability for unrecognized tax benefits was $80 million, $99 million and $98 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $1 million, $2 million and $3 million at December 31, 2011, 2010 and 2009, respectively. The following table presents the changes to unrecognized tax benefits during the years ended December 31:

(in millions)	**2011**	2010	2009
Unrecognized tax benefits at beginning of period	**$ 99**	$ 98	$ 62
Gross amounts of increases as a result of tax positions taken in a prior period	**66**	2	5
Gross amounts of decreases as a result of tax positions taken in a prior period	**(21)**	(1)	(1)
Gross amounts of increases as a result of tax positions taken in the current period	**1**	3	35
Gross amounts of decreases as a result of tax positions taken in the current period	**(4)**	(3)	(3)
Amounts of net decreases relating to settlements with taxing authorities	**(61)**	-	-
Unrecognized tax benefits at end of period	**$ 80**	$ 99	$ 98

We file consolidated federal and state income tax returns that include PEF. PEF's open federal tax years are from 2007 forward, and PEF's open state tax years generally are from 2003 forward. In 2011, the IRS completed its examination of the 2004 and 2005 tax years. It is reasonably possible that unrecognized tax benefits will decrease by approximately $20 million during the 12-month period ending December 31, 2012, due to IRS review of open tax years. Any potential decrease will not have a material impact on our results of operations.

Pursuant to a regulatory order, PEF records interest expense related to unrecognized tax benefits as a regulatory asset, which is amortized over a three-year period or less, with the amortization included in net interest charges on the Statements of Income. Penalties are included in other, net on the Statements of Income. During 2011, 2010 and 2009, interest (benefit) expense recorded as a regulatory asset was $(22) million, $5 million and $5 million, respectively, and there were no penalties recorded related to unrecognized tax benefits. During 2011, PEF charged the unamortized balance of the regulatory asset to interest expense. At December 31, 2011, 2010 and 2009, PEF accrued $7 million, $29 million and $24 million, respectively, for interest and penalties, which were included in prepayments and other current assets and other liabilities and deferred credits on the Balance Sheets.

16. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four coal-based solid synthetic fuels limited liability companies, three of which were wholly owned (Earthco), purchased by subsidiaries of Florida Progress in October 1999. All of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007 (See Note 4A). The payments are based on the net after-tax cash flows the facilities generated. We make deposits into a CVO trust for estimated contingent payments due to CVO holders based on the results of operations and the utilization of tax credits. The balance of the CVO trust at December 31, 2011 and 2010, was $11 million and is included in other assets and deferred debits on the Consolidated Balance Sheets. Future payments from the trust to CVO holders will not be made until certain conditions are satisfied and will include principal and interest earned during the investment period net of expenses deducted. Interest earned on the payments held in trust for 2011 and 2010 was insignificant.

On June 10, 2011, Davidson Kempner Partners, M.H. Davidson & Co., Davidson Kempner Institutional Partners, L.P., and Davidson Kempner International, Ltd. (jointly, Davidson Kempner) filed a lawsuit against us (see Note 22D) related to their ownership of CVOs. On October 3, 2011, we entered a settlement agreement and release with Davidson Kempner under which the parties mutually released all claims related to the CVOs and we purchased all of Davidson Kempner's CVOs at a negotiated purchase price of $0.75 per CVO. In November 2011, we also commenced a tender offer for all remaining outstanding CVOs at the same purchase price. The tender offer expired on February 15, 2012, and as a result, 83.4 million CVOs were repurchased through the settlement agreement or through the tender offer. The CVOs are derivatives and are recorded at fair value. At September 30, 2011, the purchase price included in the settlement agreement and subsequent tender offer represented the fair value of the CVOs. Prior to September 30, 2011, and at December 31, 2011, the CVOs were recorded at fair value based on observable prices from a less-than-active market (see Note 14). A pre-tax loss of $59 million from the changes in fair value during 2011 is recorded in other, net on the Consolidated Statements of Income. At December 31, 2011, the CVO liability included in other current liabilities on our Consolidated Balance Sheets was $14 million based on the 18.5 million outstanding CVOs not held by the Parent. At December 31, 2010, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million based on the 98.6 million CVOs outstanding.

17. BENEFIT PLANS

A. POSTRETIREMENT BENEFITS

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

COSTS OF BENEFIT PLANS

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

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

The tables below provide the components of the net periodic benefit cost for the years ended December 31. A portion of net periodic benefit cost is capitalized as part of construction work in progress.

PROGRESS ENERGY

	Pension Benefits			OPEB		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Service cost	**$ 53**	$ 48	$ 42	**$ 11**	$ 16	$ 7
Interest cost	**141**	140	138	**41**	45	31
Expected return on plan assets	**(182)**	(157)	(133)	**(2)**	(4)	(4)
Amortization of actuarial loss[a]	**69**	51	54	**12**	13	1
Other amortization, net[a]	**7**	6	6	**5**	5	5
Net periodic cost before deferral[b]	**$ 88**	$ 88	$ 107	**$ 67**	$ 75	$ 40

[a] Adjusted to reflect PEF's rate treatment (See Note 17B).

[b] PEF received permission from the FPSC to defer the retail portion of certain 2009 pension expense. The FPSC order did not change the total net periodic pension cost, but deferred a portion of the costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension costs as a regulatory asset. See Note 8C.

PEC

	Pension Benefits			OPEB		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Service cost	**$ 21**	$ 19	$ 18	**$ 5**	$ 5	$ 5
Interest cost	**63**	64	64	**20**	20	16
Expected return on plan assets	**(91)**	(77)	(67)	**-**	(2)	(2)
Amortization of actuarial loss	**26**	16	11	**5**	4	-
Other amortization, net	**5**	6	6	**1**	1	1
Net periodic cost	**$ 24**	$ 28	$ 32	**$ 31**	$ 28	$ 20

PEF

	Pension Benefits			OPEB		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Service cost	**$ 25**	$ 22	$ 19	**$ 5**	$ 10	$ 2
Interest cost	**59**	59	56	**18**	22	13
Expected return on plan assets	**(78)**	(68)	(56)	**(2)**	(2)	(1)
Amortization of actuarial loss	**33**	31	38	**7**	9	-
Other amortization, net	**-**	-	-	**4**	4	3
Net periodic cost before deferral[a]	**$ 39**	$ 44	$ 57	**$ 32**	$ 43	$ 17

[a] PEF received permission from the FPSC to defer the retail portion of certain 2009 pension expense. The FPSC order did not change the total net periodic pension cost, but deferred a portion of the costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension costs as a regulatory asset. See Note 8C.

The following tables provide a summary of amounts recognized in other comprehensive income and other comprehensive income reclassification adjustments for amounts included in net income for 2011, 2010 and 2009. The tables also include comparable items that affected regulatory assets. Amounts that would otherwise be recorded in other comprehensive income are recorded as adjustments to regulatory assets consistent with the recovery of the related costs through the ratemaking process.

PROGRESS ENERGY

	Pension Benefits			OPEB		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Other comprehensive income (loss)						
Recognized for the year						
Net actuarial (loss) gain	**$ (20)**	$ (11)	$ (1)	**$ (2)**	$ (10)	$ 4
Regulatory asset adjustment	**84**	-	-	**(4)**	-	-
Reclassification adjustments						
Net actuarial loss	**10**	4	5	**-**	-	1
Other, net	**2**	-	-	**-**	-	1
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	**(307)**	(65)	10	**(95)**	(164)	64
Reclassification adjustment	**(84)**	-	-	**4**	-	-
Other, net	**-**	-	(3)	**-**	-	-
Amortized to income[a]						
Net actuarial loss	**59**	47	49	**12**	13	-
Other, net	**5**	6	6	**5**	5	4

[a] These amounts were amortized as a component of net periodic cost, as reflected in the previous net periodic cost table. Refer to that table for information regarding the deferral of a portion of net periodic pension cost.

PEC

(in millions)	Pension Benefits **2011**	Pension Benefits 2010	Pension Benefits 2009	OPEB **2011**	OPEB 2010	OPEB 2009
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	**$ (134)**	$ (24)	$ (14)	**$ (49)**	$ (64)	$ 38
Other, net	**-**	-	(2)	**-**	-	-
Amortized to income						
Net actuarial loss	**26**	16	11	**5**	4	-
Other, net	**5**	6	6	**1**	1	1

PEF

(in millions)	Pension Benefits **2011**	Pension Benefits 2010	Pension Benefits 2009	OPEB **2011**	OPEB 2010	OPEB 2009
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	**$ (147)**	$ (41)	$ 24	**$ (39)**	$ (100)	$ 26
Other, net	**-**	-	(1)	**-**	-	-
Amortized to income[(a)]						
Net actuarial loss	**33**	31	38	**7**	9	-
Other, net	**-**	-	-	**4**	4	3

(a) These amounts were amortized as a component of net periodic cost, as reflected in the previous net periodic cost table. Refer to that table for information regarding the deferral of a portion of net periodic pension cost.

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

	Pension Benefits **2011**	Pension Benefits 2010	Pension Benefits 2009	OPEB **2011**	OPEB 2010	OPEB 2009
Discount rate	**5.60%**	6.00%	6.30%	**5.70%**	6.05%	6.20%
Rate of increase in future compensation						
Bargaining	**4.50%**	4.50%	4.25%	**-**	-	-
Supplementary plans	**5.25%**	5.25%	5.25%	**-**	-	-
Expected long-term rate of return on plan assets	**8.50%**	8.75%	8.75%	**5.00%**	6.60%	6.80%

The weighted-average actuarial assumptions used by PEC and PEF were not materially different from the assumptions above, as applicable, except that the expected long-term rate of return on OPEB plan assets was 5.00% for PEF for all years presented and for PEC was 8.75% for 2010 and 2009. PEC held no OPEB plan assets during 2011.

The expected long-term rates of return on plan assets were determined by considering long-term projected returns based on the plans’ target asset allocations. Specifically, return rates were developed for each major asset class and weighted based on the target asset allocations. The projected returns were benchmarked against historical returns for reasonableness. We decreased our expected long-term rate of return on pension assets by 0.25% in 2011, primarily due to a shift in our investment strategy. See the “Assets of Benefit Plans” section below for additional information regarding our investment policies and strategies.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

GAAP requires us to recognize in our statement of financial condition the funded status of our pension and other postretirement benefit plans, measured as the difference between the fair value of the plan assets and the benefit obligation as of the end of the fiscal year.

Reconciliations of the changes in the Progress Registrants' benefit obligations and the funded status as of December 31, 2011 and 2010 are presented in the tables below, with each table followed by related supplementary information.

PROGRESS ENERGY

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Projected benefit obligation at January 1	**$ 2,609**	$ 2,422	**$ 733**	$ 543
Service cost	**53**	48	**11**	16
Interest cost	**141**	140	**41**	45
Settlements	**(6)**	-	**-**	-
Benefit payments	**(129)**	(129)	**(42)**	(44)
Plan amendment	**-**	1	**-**	-
Actuarial loss	**238**	127	**98**	173
Obligation at December 31	**2,906**	2,609	**841**	733
Fair value of plan assets at December 31	**2,191**	1,891	**37**	33
Funded status	**$ (715)**	$ (718)	**$ (804)**	$ (700)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.906 billion and $2.609 billion at December 31, 2011 and 2010, respectively. Those plans had accumulated benefit obligations totaling $2.854 billion and $2.563 billion at December 31, 2011 and 2010, respectively, and plan assets of $2.191 billion and $1.891 billion at December 31, 2011 and 2010, respectively.

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

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Current liabilities	**$ (10)**	$ (10)	**$ (22)**	$ (22)
Noncurrent liabilities	**(705)**	(708)	**(782)**	(678)
Funded status	**$ (715)**	$ (718)	**$ (804)**	$ (700)

The following table provides a summary of amounts not yet recognized as a component of net periodic cost at December 31:

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Recognized in accumulated other comprehensive loss				
Net actuarial loss	**$ 34**	$ 90	**$ -**	$ 5
Other, net	**2**	9	**-**	1
Recognized in regulatory assets, net				
Net actuarial loss	**1,139**	824	**274**	183
Other, net	**56**	55	**3**	9
Total not yet recognized as a component of net periodic cost[(a)]	**$ 1,231**	$ 978	**$ 277**	$ 198

[(a)] All components are adjusted to reflect PEF's rate treatment (See Note 17B).

The following table presents the amounts we expect to recognize as components of net periodic cost in 2012:

(in millions)	Pension Benefits	OPEB
Amortization of actuarial loss[(a)]	$ 91	$ 23
Amortization of other, net[(a)]	9	4

(a) Adjusted to reflect PEF's rate treatment (See Note 17B).

PEC

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Projected benefit obligation at January 1	**$ 1,188**	$ 1,120	**$ 352**	$ 282
Service cost	**21**	19	**5**	5
Interest cost	**63**	64	**20**	20
Benefit payments	**(56)**	(56)	**(19)**	(19)
Actuarial loss	**86**	41	**49**	64
Obligation at December 31	**1,302**	1,188	**407**	352
Fair value of plan assets at December 31	**1,091**	884	**-**	-
Funded status	**$ (211)**	$ (304)	**$ (407)**	$ (352)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $1.302 billion and $1.188 billion at December 31, 2011 and 2010, respectively. Those plans had accumulated benefit obligations totaling $1.297 billion and $1.184 billion at December 31, 2011 and 2010, respectively, and plan assets of $1.091 billion and $884 million at December 31, 2011 and 2010, respectively.

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

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Current liabilities	**$ (2)**	$ (2)	**$ (19)**	$ (19)
Noncurrent liabilities	**(209)**	(302)	**(388)**	(333)
Funded status	**$ (211)**	$ (304)	**$ (407)**	$ (352)

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

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Recognized in regulatory assets				
Net actuarial loss	**$ 527**	$ 418	**$ 121**	$ 76
Other, net	**43**	49	**-**	2
Total not yet recognized as a component of net periodic cost	**$ 570**	$ 467	**$ 121**	$ 78

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2012:

(in millions)	Pension Benefits	OPEB
Amortization of actuarial loss	$ 37	$ 11
Amortization of other, net	8	-

PEF

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Projected benefit obligation at January 1	**$ 1,087**	$ 992	**$ 326**	$ 219
Service cost	**25**	22	**5**	10
Interest cost	**59**	59	**18**	22
Plan amendment	**-**	1	**-**	-
Benefit payments	**(58)**	(58)	**(21)**	(23)
Actuarial loss	**110**	71	**40**	98
Obligation at December 31	**1,223**	1,087	**368**	326
Fair value of plan assets at December 31	**969**	871	**37**	33
Funded status	**$ (254)**	$ (216)	**$ (331)**	$ (293)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $1.223 billion and $1.087 billion at December 31, 2011 and 2010, respectively. Those plans had accumulated benefit obligations totaling $1.184 billion and $1.049 billion at December 31, 2011 and 2010, respectively, and plan assets of $969 million and $871 million at December 31, 2011 and 2010, respectively.

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

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Current liabilities	**$ (3)**	$ (3)	**$ -**	$ -
Noncurrent liabilities	**(251)**	(213)	**(331)**	(293)
Funded status	**$ (254)**	$ (216)	**$ (331)**	$ (293)

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

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Recognized in regulatory assets, net				
Net actuarial loss	**$ 520**	$ 406	**$ 139**	$ 107
Other, net	**6**	6	**3**	7
Total not yet recognized as a component of net periodic cost	**$ 526**	$ 412	**$ 142**	$ 114

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2012:

(in millions)	Pension Benefits	OPEB
Amortization of actuarial loss	$ 45	$ 12
Amortization of other, net	-	3

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

	Pension Benefits		OPEB	
	2011	2010	**2011**	2010
Discount rate	**4.75%**	5.65%	**4.85%**	5.75%
Rate of increase in future compensation				
Bargaining	**4.00%**	4.50%	**-**	-
Supplementary plans	**5.25%**	5.25%	**-**	-
Initial medical cost trend rate for pre-Medicare Act benefits	**-**	-	**8.75%**	8.50%
Initial medical cost trend rate for post-Medicare Act benefits	**-**	-	**8.75%**	8.50%
Ultimate medical cost trend rate	**-**	-	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	**-**	-	**2020**	2017

The weighted-average actuarial assumptions for PEC and PEF were the same or were not significantly different from those indicated above, as applicable. The rates of increase in future compensation include the effects of cost of living adjustments and promotions.

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan. Therefore, we use the traditional unit credit method for purposes of measuring the benefit obligation of this plan. Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. The effects of a 1 percent change in the medical cost trend rate are shown below.

	Progress Energy	PEC	PEF
1 percent increase in medical cost trend rate			
Effect on total of service and interest cost	$ 3	$ 1	$ 1
Effect on postretirement benefit obligation	43	21	19
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(2)	(1)	(1)
Effect on postretirement benefit obligation	(31)	(15)	(14)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our, PEC's and PEF's employer contributions to qualified plans for 2011 include contributions directly to pension plan assets of $334 million, $217 million and $112 million, respectively, and for 2010 include contributions directly to pension plan assets of $129 million, $95 million and $34 million, respectively. Substantially all of the remaining employer contributions represent benefit payments made directly from the Progress Registrants' assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the cost after participant contributions. Participant contributions represent approximately 16 percent of gross benefit payments for Progress Energy, 21 percent for PEC and 12 percent for PEF. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2011, the subsidies totaled $5 million for us, $2 million for PEC and $2 million for PEF. In 2010, the subsidies totaled $3 million for us, $1 million for PEC and $2 million for PEF.

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

PROGRESS ENERGY

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Fair value of plan assets January 1	**$ 1,891**	$ 1,673	**$ 33**	$ 55
Actual return on plan assets	**91**	208	**3**	2
Benefit payments, including settlements	**(135)**	(129)	**(42)**	(44)
Employer contributions	**344**	139	**43**	20
Fair value of plan assets at December 31	**$ 2,191**	$ 1,891	**$ 37**	$ 33

PEC

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Fair value of plan assets January 1	**$ 884**	$ 749	**$ -**	$ 21
Actual return on plan assets	**44**	94	**-**	2
Benefit payments	**(56)**	(56)	**(19)**	(19)
Employer contributions (reimbursements)	**219**	97	**19**	(4)
Fair value of plan assets at December 31	**$ 1,091**	$ 884	**$ -**	$ -

PEF

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Fair value of plan assets January 1	**$ 871**	$ 794	**$ 33**	$ 32
Actual return on plan assets	**41**	98	**4**	1
Benefit payments	**(58)**	(58)	**(21)**	(23)
Employer contributions	**115**	37	**21**	23
Fair value of plan assets at December 31	**$ 969**	$ 871	**$ 37**	$ 33

The Progress Registrants' primary objectives when setting investment policies and strategies are to manage the assets of the pension plan to ensure that sufficient funds are available at all times to finance promised benefits and to invest the funds such that contributions are minimized, within acceptable risk limits. We periodically perform studies to analyze various aspects of our pension plans including asset allocations, expected portfolio return, pension contributions and net funded status. One of our key investment objectives is to achieve a rate of return significantly in excess of the discount rate used to measure the plan liabilities over the long term. As of December 31, 2011, the target pension asset allocations are 29 percent domestic equity, 19 percent international equity, 35 percent domestic fixed income, 10 percent private equity and timber and 7 percent absolute return hedge funds. Tactical shifts (plus or minus 5 percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes. Domestic equity includes investments across large, medium and small capitalized domestic stocks, using investment managers with value, growth and core-based investment strategies and includes both long only and long/short equity managers. International equity includes investments in foreign stocks in both developed and emerging market countries, using a mix of value and growth-based investment strategies and includes both long only and long/short equity managers. Domestic fixed income primarily includes domestic investment grade long duration fixed income investments. OPEB plan assets, representing all PEF's OPEB plan assets, are invested in domestic governmental securities.

PROGRESS ENERGY

The following table sets forth by level within the fair value hierarchy our pension plan assets at December 31, 2011 and 2010. See Note 14 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				
Cash and cash equivalents	**$ 82**	**$ 33**	**$ -**	**$ 115**
International equity securities	**47**	**-**	**-**	**47**
Domestic equity securities	**266**	**-**	**-**	**266**
Private equity securities	**-**	**-**	**153**	**153**
Corporate bonds	**-**	**407**	**-**	**407**
U.S. state and municipal debt	**-**	**42**	**-**	**42**
U.S. and foreign government debt	**247**	**102**	**-**	**349**
Commingled funds	**-**	**490**	**-**	**490**
Hedge funds	**-**	**159**	**147**	**306**
Timber investments	**-**	**-**	**11**	**11**
Other investments	**-**	**5**	**-**	**5**
Fair value of plan assets	**$ 642**	**$ 1,238**	**$ 311**	**$ 2,191**

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2010				
Assets				
Cash and cash equivalents	$ -	$ 94	$ -	$ 94
International equity securities	40	-	-	40
Domestic equity securities	286	-	-	286
Private equity securities	-	-	147	147
Corporate bonds	-	216	-	216
U.S. state and municipal debt	-	19	-	19
U.S. and foreign government debt	144	30	-	174
Commingled funds	-	847	-	847
Hedge funds	-	51	2	53
Timber investments	-	-	11	11
Other investments	-	4	-	4
Fair value of plan assets	$ 470	$ 1,261	$ 160	$ 1,891

Our other postretirement benefit plan assets had a fair value of $37 million and $33 million, which consisted of U.S. state and municipal assets classified as Level 2 in the fair value hierarchy at December 31, 2011, and December 31, 2010, respectively.

A reconciliation of changes in the fair value of our pension plan assets classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2011				
Balance at January 1	**$ 147**	**$ 2**	**$ 11**	**$ 160**
Net realized and unrealized gains[a]	**-**	**4**	**1**	**5**
Transfers in	**-**	**52**	**-**	**52**
Purchases, sales and distributions, net	**6**	**89**	**(1)**	**94**
Balance at December 31	**$ 153**	**$ 147**	**$ 11**	**$ 311**

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2010				
Balance at January 1	$ 122	$ 2	$ 14	$ 138
Net realized and unrealized gains (losses)[a]	7	-	(2)	5
Purchases, sales and distributions, net	18	-	(1)	17
Balance at December 31	$ 147	$ 2	$ 11	$ 160

[a] Substantially all amounts relate to investments held at December 31.

PEC

The following table sets forth by level within the fair value hierarchy PEC's pension plan assets at December 31, 2011 and 2010. See Note 14 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				
Cash and cash equivalents	**$ 41**	**$ 16**	**$ -**	**$ 57**
International equity securities	**24**	**-**	**-**	**24**
Domestic equity securities	**133**	**-**	**-**	**133**
Private equity securities	**-**	**-**	**76**	**76**
Corporate bonds	**-**	**203**	**-**	**203**
U.S. state and municipal debt	**-**	**21**	**-**	**21**
U.S. and foreign government debt	**123**	**51**	**-**	**174**
Commingled funds	**-**	**244**	**-**	**244**
Hedge funds	**-**	**79**	**73**	**152**
Timber investments	**-**	**-**	**5**	**5**
Other investments	**-**	**2**	**-**	**2**
Fair value of plan assets	**$ 321**	**$ 616**	**$ 154**	**$ 1,091**

(in millions)	Pension Benefit Plan Assets Level 1	Level 2	Level 3	Total
2010				
Assets				
Cash and cash equivalents	$ -	$ 44	$ -	$ 44
International equity securities	19	-	-	19
Domestic equity securities	134	-	-	134
Private equity securities	-	-	69	69
Corporate bonds	-	101	-	101
U.S. state and municipal debt	-	9	-	9
U.S. and foreign government debt	67	14	-	81
Commingled funds	-	396	-	396
Hedge funds	-	24	1	25
Timber investments	-	-	5	5
Other investments	-	1	-	1
Fair value of plan assets	$220	$ 589	$ 75	$ 884

A reconciliation of changes in the fair value of PEC's pension plan assets classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

(in millions)	**Private Equity Securities**	**Hedge Funds**	**Timber Investments**	**Total**
2011				
Balance at January 1	**$ 69**	**$ 1**	**$ 5**	**$ 75**
Net realized and unrealized gains[(a)]	**-**	**2**	**-**	**2**
Transfers in	**-**	**26**	**-**	**26**
Purchases, sales and distributions, net	**7**	**44**	**-**	**51**
Balance at December 31	**$ 76**	**$ 73**	**$ 5**	**$ 154**

(in millions)	**Private Equity Securities**	**Hedge Funds**	**Timber Investments**	**Total**
2010				
Balance at January 1	$ 55	$ 1	$ 6	$ 62
Net realized and unrealized gains (losses)[(a)]	4	-	(1)	3
Purchases, sales and distributions, net	10	-	-	10
Balance at December 31	$ 69	$ 1	$ 5	$ 75

(a) Substantially all amounts relate to investments held at December 31.

PEF

The following table sets forth by level within the fair value hierarchy PEF's pension assets at December 31, 2011 and 2010. See Note 14 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				
Cash and cash equivalents	**$ 36**	**$ 15**	**$ -**	**$ 51**
International equity securities	**21**	**-**	**-**	**21**
Domestic equity securities	**117**	**-**	**-**	**117**
Private equity securities	**-**	**-**	**68**	**68**
Corporate bonds	**-**	**180**	**-**	**180**
U.S. state and municipal debt	**-**	**19**	**-**	**19**
U.S. and foreign government debt	**109**	**45**	**-**	**154**
Commingled funds	**-**	**217**	**-**	**217**
Hedge funds	**-**	**70**	**65**	**135**
Timber investments	**-**	**-**	**5**	**5**
Other investments	**-**	**2**	**-**	**2**
Fair value of plan assets	**$ 283**	**$ 548**	**$ 138**	**$ 969**

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2010				
Assets				
Cash and cash equivalents	$ -	$ 43	$ -	$ 43
International equity securities	18	-	-	18
Domestic equity securities	132	-	-	132
Private equity securities	-	-	68	68
Corporate bonds	-	99	-	99
U.S. state and municipal debt	-	9	-	9
U.S. and foreign government debt	66	14	-	80
Commingled funds	-	391	-	391
Hedge funds	-	23	1	24
Timber investments	-	-	5	5
Other investments	-	2	-	2
Fair value of plan assets	$ 216	$ 581	$ 74	$ 871

PEF's other postretirement benefit plan assets had a fair value of $37 million and $33 million, which consisted of U.S. state and municipal assets classified as Level 2 in the fair value hierarchy at December 31, 2011 and 2010, respectively.

A reconciliation of changes in the fair value of PEF's pension plan assets classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

(in millions)	**Private Equity Securities**	**Hedge Funds**	**Timber Investments**	**Total**
2011				
Balance at January 1	**$ 68**	**$ 1**	**$ 5**	**$ 74**
Net realized and unrealized gains[(a)]	**-**	**2**	**-**	**2**
Transfers in	**-**	**23**	**-**	**23**
Purchases, sales and distributions, net	**-**	**39**	**-**	**39**
Balance at December 31	**$ 68**	**$ 65**	**$ 5**	**$ 138**

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2010				
Balance at January 1	$ 58	$ 1	$ 7	$ 66
Net realized and unrealized gains (losses)[(a)]	3	-	(1)	2
Purchases, sales and distributions, net	7	-	(1)	6
Balance at December 31	$ 68	$ 1	$ 5	$ 74

[(a)] Substantially all amounts relate to investments held at December 31.

For Progress Energy, PEC and PEF, the determination of the fair values of pension and postretirement plan assets incorporates various factors required under GAAP. The assets of the plan include exchange traded securities (classified within Level 1) and other marketable debt and equity securities, most of which are valued using Level 1 inputs for similar instruments, and are classified within Level 2 investments.

Most over-the-counter investments are valued using observable inputs for similar instruments or prices from similar transactions and are classified as Level 2. Over-the-counter investments where significant unobservable inputs are used, such as financial pricing models, are classified as Level 3 investments.

Investments in private equity are valued using observable inputs, when available, and also include comparable market transactions, income and cost basis valuation techniques. The market approach includes using comparable market transactions or values. The income approach generally consists of the net present value of estimated future cash flows, adjusted as appropriate for liquidity, credit, market and/or other risk factors. Private equity investments are classified as Level 3 investments.

Investments in commingled funds are not publically traded, but the underlying assets held in these funds are traded in active markets and the prices for these assets are readily observable. Holdings in commingled funds are classified as Level 2 investments.

Hedge funds are based primarily on the net asset values and other financial information provided by management of the private investment funds. Hedge funds are classified as Level 2 if the plan is able to redeem the investment with the investee at net asset value as of the measurement date, or at a later date within a reasonable period of time. Hedge funds are classified as Level 3 if the investment cannot be redeemed at net asset value or it cannot be determined when the fund will be redeemed.

Investments in timber are valued primarily on valuations prepared by independent property appraisers. These appraisals are based on cash flow analysis, current market capitalization rates, recent comparable sales transactions, actual sales negotiations and bona fide purchase offers. Inputs include the species, age, volume and condition of timber stands growing on the land; the location, productivity, capacity and accessibility of the timber tracts; current and expected log prices; and current local prices for comparable investments. Timber investments are classified as Level 3 investments.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2012, we expect to make contributions of $125 million-$225 million 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 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $182, $185, $193, $198, $200 and $1,046, respectively. The expected benefit payments for the OPEB plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $47, $50, $53, $56, $58 and $318, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from our assets. The benefit payment amounts reflect our net cost after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $4, $5, $5, $6, $7 and $44, respectively.

In 2012, PEC expects to make contributions of $60 million-$110 million directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $94, $94, $99, $99, $97 and $479, respectively. The expected benefit payments for the OPEB plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $21, $23, $25, $26, $28 and $158, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from PEC assets. The benefit payment amounts reflect the net cost to PEC after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $2, $2, $3, $3, $3 and $23, respectively.

In 2012, PEF expects to make contributions of $65 million-$115 million directly to pension plan assets and expects to make $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $64, $67, $70, $73, $76 and $430, respectively. The expected benefit payments for the OPEB plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $23, $24, $25, $25, $26 and $137, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from PEF's assets. The benefit payment amounts reflect the net cost to PEF after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $2, $2, $2, $3, $3 and $17, respectively.

The Patient Protection and Affordable Care Act (PPACA) and the related Health Care and Education Reconciliation Act, which made various amendments to the PPACA, were enacted in March 2010. The PPACA contains a provision that changes the tax treatment related to a federal subsidy available to sponsors of retiree health benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to the benefits under Medicare Part D. The subsidy is known as the Retiree Drug Subsidy. Employers are not currently taxed on the Retiree Drug Subsidy payments they receive. However, as a result of the PPACA as amended, Retiree Drug Subsidy payments will effectively become taxable in tax years beginning after December 31, 2012, by requiring the amount of the subsidy received to be offset against the employer's deduction for health care expenses. Under GAAP, changes in tax law are accounted for in the period of enactment. Accordingly, an additional tax expense of $22 million for us, including $12 million for PEC and $10 million for PEF, was recognized during the year ended December 31, 2010.

B. FLORIDA PROGRESS ACQUISITION

During 2000, we completed our acquisition of Florida Progress. Florida Progress' pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of Florida Progress' nonbargaining unit benefit plans were merged with our benefit plans effective January 1, 2002.

PEF continues to recover qualified plan pension costs and OPEB costs in rates as if the acquisition had not occurred. The information presented in Note 17A is adjusted as appropriate to reflect PEF's rate treatment.

18. RISK MANAGEMENT ACTIVITIES AND DERIVATIVE TRANSACTIONS

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

See Note 14B for information about the fair value of derivatives.

A. COMMODITY DERIVATIVES

GENERAL

Most of our physical commodity contracts are not derivatives or qualify as normal purchases or sales. Therefore, such contracts are not recorded at fair value.

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions.

The Utilities have financial derivative instruments with settlement dates through 2015 related to their exposure to price fluctuations on fuel oil and natural gas purchases. The majority of our financial hedge agreements will settle in 2012 and 2013. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Balance Sheets until the contracts are settled (See Note 8A). After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause.

Certain hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

Certain counterparties have posted or held cash collateral in support of these instruments. Progress Energy had a cash collateral asset included in derivative collateral posted of $147 million and $164 million on the Progress Energy Consolidated Balance Sheets at December 31, 2011 and 2010, respectively. At December 31, 2011, Progress Energy had 380.0 million MMBtu notional of natural gas and 10.3 million gallons notional of oil related to outstanding commodity derivative swaps and options that were entered into to hedge forecasted natural gas and oil purchases.

PEC had a cash collateral asset included in prepayments and other current assets of $24 million on the PEC Consolidated Balance Sheets at December 31, 2011 and 2010. At December 31, 2011, PEC had 111.4 million MMBtu notional of natural gas related to outstanding commodity derivative swaps that were entered into to hedge forecasted natural gas purchases.

PEF's cash collateral asset included in derivative collateral posted was $123 million and $140 million on the PEF Balance Sheets at December 31, 2011 and 2010, respectively. At December 31, 2011, PEF had 268.6 million MMBtu notional of natural gas and 10.3 million gallons notional of oil related to outstanding commodity derivative swaps and options that were entered into to hedge forecasted natural gas and oil purchases.

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

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

CASH FLOW HEDGES

At December 31, 2011, all open interest rate hedges will reach their mandatory termination dates within two years. At December 31, 2011, including amounts related to terminated hedges, we had $141 million of after-tax losses, including $71 million and $25 million of after-tax losses at PEC and PEF, respectively, recorded in accumulated other comprehensive loss related to forward starting swaps. It is expected that in the next 12 months losses of $12 million, net of tax, primarily related to terminated hedges, will be reclassified to interest expense at Progress Energy, including $6 million and $2 million at PEC and PEF, respectively. The actual amounts that will be reclassified to earnings may vary from the expected amounts as a result of changes in interest rates, changes in the timing of debt issuances at the Parent and the Utilities and changes in market value of currently open forward starting swaps.

At December 31, 2010, including amounts related to terminated hedges, we had $63 million of after-tax losses, including $33 million and $4 million of after-tax losses at PEC and PEF, respectively, recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2009, including amounts related to terminated hedges, we had $35 million of after-tax losses, including $27 million of after-tax losses at PEC and $3 million of after-tax gains at PEF, recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2011, Progress Energy had $500 million notional of open forward starting swaps, including $250 million at PEC and $50 million at PEF.

At December 31, 2010, Progress Energy had $1.050 billion notional of open forward starting swaps, including $350 million at PEC and $200 million at PEF.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At December 31, 2011 and 2010, neither we nor the Utilities had any outstanding positions in such contracts.

C. CONTINGENT FEATURES

Certain of our commodity derivative instruments contain provisions defining fair value thresholds requiring the posting of collateral for hedges in a liability position greater than such threshold amounts. The thresholds are tiered and based on the individual company's credit rating with Moody's, S&P and/or Fitch Ratings (Fitch). Higher credit ratings have a higher threshold requiring a lower amount of the outstanding liability position to be covered by posted collateral. Conversely, lower credit ratings require a higher amount of the outstanding liability position to be covered by posted collateral. If our credit ratings were to be downgraded, we may have to post additional collateral on certain hedges in liability positions.

In addition, certain of our commodity derivative instruments contain provisions that require our debt to maintain an investment grade credit rating from Moody's, S&P and/or Fitch. If our debt were to fall below investment grade, we would be in violation of these provisions, and the counterparties to the commodity derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on commodity derivative instruments in net liability positions.

The aggregate fair value of all commodity derivative instruments at Progress Energy with credit risk-related contingent features that are in a net liability position was $489 million at December 31, 2011, for which Progress Energy has posted collateral of $147 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2011, Progress Energy would have been required to post an additional $342 million of collateral with its counterparties.

The aggregate fair value of all commodity derivative instruments at PEC with credit risk-related contingent features that are in a liability position was $152 million at December 31, 2011, for which PEC has posted collateral of $24 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2011, PEC would have been required to post an additional $128 million of collateral with its counterparties.

The aggregate fair value of all commodity derivative instruments at PEF with credit risk-related contingent features that are in a net liability position was $337 million at December 31, 2011, for which PEF has posted collateral of $123 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered on December 31, 2011, PEF would have been required to post an additional $214 million of collateral with its counterparties.

D. DERIVATIVE INSTRUMENT AND HEDGING ACTIVITY INFORMATION

PROGRESS ENERGY

The following table presents the fair value of derivative instruments at December 31:

Instrument / Balance sheet location	**2011**		2010	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		**$ 2**		$ -
Derivative liabilities, long-term		**1**		-
Interest rate derivatives				
Prepayments and other current assets	**$ -**		$ 1	
Other assets and deferred debits	**-**		3	
Derivative liabilities, current		**76**		32
Derivative liabilities, long-term		**17**		7
Total derivatives designated as hedging instruments	**-**	**96**	4	39
Derivatives not designated as hedging instruments				
Commodity derivatives[(a)]				
Prepayments and other current assets	**5**		11	
Other assets and deferred debits	**-**		4	
Derivative liabilities, current		**357**		226
Derivative liabilities, long-term		**332**		268
CVOs[(b)]				
Other current liabilities		**14**		-
Other liabilities and deferred credits		**-**		15
Fair value of derivatives not designated as hedging instruments	**5**	**703**	15	509
Fair value loss transition adjustment[(c)]				
Derivative liabilities, current		**1**		1
Derivative liabilities, long-term		**2**		3
Total derivatives not designated as hedging instruments	**5**	**706**	15	513
Total derivatives	**$ 5**	**$ 802**	$ 19	$ 552

(a) Substantially all of these contracts receive regulatory treatment.
(b) The Parent issued 98.6 million CVOs in connection with the acquisition of Florida Progress during 2000. In 2011, we purchased 80.1 million CVOs in a negotiated settlement agreement and subsequent tender offer. (See Note 16)
(c) In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contracts.

The following tables present the effect of derivative instruments on the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Income for the years ended December 31:

Derivatives Designated as Hedging Instruments

Instrument	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[(a)]			Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[(a)]			Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[(b)]		
(in millions)	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Commodity cash flow derivatives[(c)]	**$ (2)**	$ -	$ 1	**$ -**	$ -	$ -	**$ -**	$ -	$ -
Interest rate derivatives[(d)] [(e)]	**(85)**	(34)	15	**(8)**	(6)	(6)	**(3)**	3	(3)
Total	**$ (87)**	$ (34)	$ 16	**$ (8)**	$ (6)	$ (6)	**$ (3)**	$ 3	$ (3)

(a) Effective portion.
(b) Related to ineffective portion and amount excluded from effectiveness testing.
(c) Amounts recorded on the Consolidated Statements of Income are classified in fuel used in electric generation.
(d) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.
(e) Amounts recorded on the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments

Instrument	Realized Gain or (Loss)[(a)]			Unrealized Gain or (Loss)[(b)]		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Commodity derivatives[(a)]	**$ (297)**	$ (324)	$ (659)	**$ (502)**	$ (398)	$ (387)

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.
(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument	Amount of Gain or (Loss) Recognized in Income on Derivatives		
(in millions)	**2011**	2010	2009
Commodity derivatives[(a)]	**$ -**	$ -	$ 1
Fair value loss transition adjustment[(a)]	**1**	1	2
CVOs[(a)]	**(59)**	-	19
Total	**$ (58)**	$ 1	$ 22

(a) Amounts recorded on the Consolidated Statements of Income are classified in other, net.

PEC

The following table presents the fair value of derivative instruments at December 31:

Instrument / Balance sheet location	2011		2010	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Interest rate derivatives				
Other assets and deferred debits	**$ -**		$ 3	
Derivative liabilities, current		**$ 38**		$ 7
Other liabilities and deferred credits		**9**		4
Total derivatives designated as hedging instruments	**-**	**47**	3	11
Derivatives not designated as hedging instruments				
Commodity derivatives[(a)]				
Prepayments and other current assets	**-**		1	
Other assets and deferred debits	**-**		1	
Derivative liabilities, current		**91**		45
Other liabilities and deferred credits		**110**		78
Fair value of derivatives not designated as hedging instruments	**-**	**201**	2	123
Fair value loss transition adjustment[(b)]				
Derivative liabilities, current		**1**		1
Other liabilities and deferred credits		**2**		3
Total derivatives not designated as hedging instruments	**-**	**204**	2	127
Total derivatives	**$ -**	**$ 251**	$ 5	$ 138

(a) Substantially all of these contracts receive regulatory treatment.

(b) In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contracts.

The following tables present the effect of derivative instruments on the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Income for the years ended December 31:

Derivatives Designated as Hedging Instruments

Instrument	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[(a)]			Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[(a)]			Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[(b)]		
(in millions)	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Interest rate derivatives[(c) (d)]	**$ (43)**	$ (10)	$ 5	**$ (5)**	$ (4)	$ (3)	**$ (1)**	$ -	$ (2)

(a) Effective portion.

(b) Related to ineffective portion and amount excluded from effectiveness testing.

(c) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

(d) Amounts recorded on the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments						
Instrument	Realized Gain or (Loss)[a]			Unrealized Gain or (Loss)[b]		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Commodity derivatives	**$ (60)**	$ (46)	$ (76)	**$ (140)**	$ (77)	$ (68)

[a] After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.
[b] Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument	Amount of Gain or (Loss) Recognized in Income on Derivatives		
(in millions)	**2011**	2010	2009
Commodity derivatives[a]	**$ -**	$ -	$ 1
Fair value loss transition adjustment[a]	**1**	1	2
Total	**$ 1**	$ 1	$ 3

[a] Amounts recorded on the Consolidated Statements of Income are classified in other, net.

PEF

The following table presents the fair value of derivative instruments at December 31:

Instrument / Balance sheet location	**2011**		2010	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		**$ 2**		$ -
Derivative liabilities, long-term		**1**		-
Interest rate derivatives				
Derivative liabilities, current		**-**		7
Derivative liabilities, long-term		**8**		-
Total derivatives designated as hedging instruments		**11**		7
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	**$ 5**		$ 10	
Other assets and deferred debits	**-**		3	
Derivative liabilities, current		**266**		181
Derivative liabilities, long-term		**222**		190
Total derivatives not designated as hedging instruments	**5**	**488**	13	371
Total derivatives	**$ 5**	**$ 499**	$ 13	$ 378

[a] Substantially all of these contracts receive regulatory treatment.

The following tables present the effect of derivative instruments on the Statements of Comprehensive Income and the Statements of Income for the years ended December 31:

Derivatives Designated as Hedging Instruments

Instrument	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a]			Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a]			Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b]		
(in millions)	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Commodity cash flow derivatives[c]	**$ (2)**	$ -	$ 1	**$ -**	$ -	$ -	**$ -**	$ -	$ -
Interest rate derivatives[d] [e]	**(21)**	(7)	3	**-**	-	-	**-**	-	-
Total	**$ (23)**	$ (7)	$ 4	**$ -**	$ -	$ -	**$ -**	$ -	$ -

[a] Effective portion.
[b] Related to ineffective portion and amount excluded from effectiveness testing.
[c] Amounts recorded on the Statements of Income are classified in fuel used in electric generation.
[d] Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.
[e] Amounts recorded on the Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments

Instrument	Realized Gain or (Loss)[a]			Unrealized Gain or (Loss)[b]		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Commodity derivatives	**$ (237)**	$ (278)	$ (583)	**$ (362)**	$ (321)	$ (319)

[a] After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.
[b] Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

19. RELATED PARTY TRANSACTIONS

There were no material related party transactions in which we or any of our subsidiaries were or will be a participant and in which any of our directors, executive officers or any of their immediate family members had a direct or indirect material interest. Transactions between affiliated companies are further discussed below.

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees may include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements, trading operations and cash management. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2011, the Parent had issued $453 million of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included on the Consolidated Balance Sheets.

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of the Public Utility Holding Company Act of 1935. The repeal of the Public Utility Holding Company Act of 1935 effective February 8, 2006, and subsequent regulation by the FERC did not change our current intercompany services. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, construction management and other centralized administrative, management and support services. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. Billings from affiliates are capitalized or expensed depending on the nature of the services rendered. Amounts receivable from and/or payable to affiliated companies for these services are included in receivables from affiliated companies and payables to affiliated companies on the Balance Sheets.

PESC provides the majority of the affiliated goods and services under the approved agreements. Goods and services provided by PESC during 2011, 2010 and 2009 to PEC amounted to \$203 million, \$176 million and \$170 million, respectively, and services provided to PEF were \$160 million, \$156 million and \$147 million, respectively. During 2010, PESC transferred a \$24 million combustion turbine to PEC at cost.

PEC and PEF also provide and receive goods and services at cost. Goods and services provided by PEC to PEF during 2011, 2010 and 2009 amounted to \$57 million, \$43 million and \$36 million, respectively. Goods and services provided by PEF to PEC during 2011, 2010 and 2009 amounted to \$12 million, \$18 million and \$12 million, respectively.

PEC and PEF participate in an internal money pool, administered by PESC, 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 0.32%, 0.30% and 0.74% for the years ended December 31, 2011, 2010 and 2009, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Balance Sheets. PEC and PEF recorded minimal interest expense related to the money pool for all the years presented.

PEC and each of its wholly owned subsidiaries and PEF have entered into the Tax Agreement with the Parent (See Note 15).

20. FINANCIAL INFORMATION BY BUSINESS SEGMENT

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

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative thresholds for disclosure as separate reportable business segments.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost.

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

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Total
At and for the year ended December 31, 2011					
Revenues					
Unaffiliated	**$ 4,528**	**$ 4,367**	**$ 12**	**$ -**	**$ 8,907**
Intersegment	**-**	**2**	**272**	**(274)**	**-**
Total revenues	**4,528**	**4,369**	**284**	**(274)**	**8,907**
Depreciation, amortization and accretion	**514**	**169**	**18**	**-**	**701**
Interest income	**1**	**1**	**22**	**(22)**	**2**
Total interest charges, net	**184**	**239**	**324**	**(22)**	**725**
Income tax expense (benefit)[(a)]	**268**	**311**	**(99)**	**-**	**480**
Ongoing Earnings	**541**	**530**	**(200)**	**-**	**871**
Total assets	**16,102**	**14,484**	**20,926**	**(16,453)**	**35,059**
Capital and investment expenditures	**1,423**	**710**	**17**	**-**	**2,150**
At and for the year ended December 31, 2010					
Revenues					
Unaffiliated	$ 4,922	$ 5,252	$ 16	$ -	$ 10,190
Intersegment	-	2	248	(250)	-
Total revenues	4,922	5,254	264	(250)	10,190
Depreciation, amortization and accretion	479	426	15	-	920
Interest income	3	1	31	(28)	7
Total interest charges, net	186	258	331	(28)	747
Income tax expense (benefit)[(a)]	342	267	(87)	-	522
Ongoing Earnings	618	462	(191)	-	889
Total assets	14,899	14,056	21,110	(17,011)	33,054
Capital and investment expenditures	1,382	991	33	(24)	2,382
At and for the year ended December 31, 2009					
Revenues					
Unaffiliated	$ 4,627	$ 5,249	$ 9	$ -	$ 9,885
Intersegment	-	2	234	(236)	-
Total revenues	4,627	5,251	243	(236)	9,885
Depreciation, amortization and accretion	470	502	14	-	986
Interest income	5	4	38	(33)	14
Total interest charges, net	195	231	286	(33)	679
Income tax expense (benefit)[(a)]	295	209	(88)	-	416
Ongoing Earnings	540	460	(154)	-	846
Total assets	13,502	13,100	20,538	(15,904)	31,236
Capital and investment expenditures	962	1,532	21	(12)	2,503

[(a)] Income tax expense (benefit) excludes the tax impact of Ongoing Earnings adjustments.

Management uses the non-GAAP financial measure "Ongoing Earnings" as a performance measure to evaluate the results of our segments and operations. Ongoing Earnings as presented here may not be comparable to similarly titled measures used by other companies. Ongoing Earnings is computed as GAAP net income attributable to controlling interests less discontinued operations and the effects of certain identified gains and charges, which are considered Ongoing Earnings adjustments. Some of the excluded gains and charges have occurred in more than one reporting period but are not considered representative of fundamental core earnings. Management has identified the following Ongoing Earnings adjustments: CVO mark-to-market adjustments because we are unable to predict changes in their fair value; CR3 indemnification charge (and subsequent adjustments, if any) for estimated future years' joint owner replacement power costs (through the expiration of the indemnification provisions of the joint owner agreement) because GAAP requires that the charge be accounted for in the period in which it becomes probable and estimable rather than the periods to which it relates; and the impact from changes in the tax treatment of the Medicare Part D subsidy because GAAP requires that the impact of the tax law change be accounted for in the period of enactment rather than the affected tax year. Additionally, management does not consider impairments, charges (and subsequent adjustments, if any) recognized for the retirement of generating units prior to the end of their estimated useful lives, merger and integration costs, cumulative prior period adjustments, operating results of discontinued operations and the amount to be refunded to customers through the fuel clause included in the terms of the 2012 settlement agreement to be representative of our ongoing operations and excluded these items in computing Ongoing Earnings.

Reconciliations of consolidated Ongoing Earnings to net income attributable to controlling interests for the years ended December 31 follow:

(in millions)	**2011**	2010	2009
Ongoing Earnings	**$ 871**	$ 889	$ 846
CVO mark-to-market, net of tax benefit of $14 and $- (Note 16)	**(45)**	-	19
Impairment, net of tax benefit of $1, $4 and $1	**(2)**	(6)	(2)
Merger and integration costs, net of tax benefit of $17 (Note 2)	**(46)**	-	-
CR3 indemnification charge, net of tax benefit of $13 (Note 22C)	**(20)**	-	-
Plant retirement charge, net of tax benefit of $1, $1 and $11	**(1)**	(1)	(17)
Amount to be refunded to customers, net of tax benefit of $111 (Note 8C)	**(177)**	-	-
Change in tax treatment of the Medicare Part D subsidy (Note 17)	**-**	(22)	-
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax benefit of $7	**-**	-	(10)
Continuing income attributable to noncontrolling interests, net of tax	**7**	7	4
Income from continuing operations	**587**	867	840
Discontinued operations, net of tax	**(5)**	(4)	(79)
Net income attributable to noncontrolling interests, net of tax	**(7)**	(7)	(4)
Net income attributable to controlling interests	$ **575**	$ 856	$ 757

21. ENVIRONMENTAL MATTERS

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

A. HAZARDOUS AND SOLID WASTE

The U.S. Environmental Protection Agency (EPA) and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion residuals, primarily ash, from each of the Utilities' coal-fired plants. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or groundwater protection environmental controls. In June 2010, the EPA proposed two options for new rules to regulate coal combustion residuals. The first option would create a comprehensive program of federally enforceable requirements for coal combustion residuals management and disposal under federal hazardous waste rules. The other option would have the EPA set design and performance standards for coal combustion residuals management facilities and regulate disposal of coal combustion residuals as nonhazardous waste with enforcement by the courts or state laws. The EPA did not identify a preferred option. Under both options, the EPA may leave in place a regulatory exemption for approved beneficial uses of coal combustion residuals that are recycled. A final rule is expected in late 2012. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures under existing regulations. These issues are also under evaluation by state agencies. Certain regulated chemicals have been measured in wells near our ash ponds at levels above groundwater quality standards. Additional monitoring and investigation will be conducted. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary. We cannot predict the outcome of this matter.

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 Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida, or potentially responsible party (PRP) groups as described below in greater detail. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted.

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

The following tables contain information about accruals for probable and estimable costs related to various environmental sites, which are included in other current liabilities and other liabilities and deferred credits on the Balance Sheets:

PROGRESS ENERGY

(in millions)	**MGP and Other Sites**	**Remediation of Distribution and Substation Transformers**	**Total**
Balance, December 31, 2008	**$ 31**	**$ 22**	**$ 53**
Amount accrued for environmental loss contingencies	3	13	16
Expenditures for environmental loss contingencies	(12)	(15)	(27)
Balance, December 31, 2009[a]	**22**	**20**	**42**
Amount accrued for environmental loss contingencies	8	13	21
Expenditures for environmental loss contingencies	(10)	(18)	(28)
Balance, December 31, 2010[a]	**20**	**15**	**35**
Amount accrued for environmental loss contingencies	**2**	**8**	**10**
Expenditures for environmental loss contingencies	**(5)**	**(17)**	**(22)**
Balance, December 31, 2011[a]	**$ 17**	**$ 6**	**$ 23**

[a] Expected to be paid out over one to 15 years.

PEC

(in millions)	**MGP and Other Sites**
Balance, December 31, 2008	**$ 16**
Amount accrued for environmental loss contingencies	3
Expenditures for environmental loss contingencies	(6)
Balance, December 31, 2009[a]	**13**
Amount accrued for environmental loss contingencies	3
Expenditures for environmental loss contingencies	(4)
Balance, December 31, 2010[a]	**12**
Amount accrued for environmental loss contingencies	**1**
Expenditures for environmental loss contingencies	**(2)**
Balance, December 31, 2011[a]	**$ 11**

[a] Expected to be paid out over one to five years.

PEF

(in millions)	MGP and Other Sites	Remediation of Distribution and Substation Transformers	Total
Balance, December 31, 2008	**$ 15**	**$ 22**	**$ 37**
Amount accrued for environmental loss contingencies	**-**	**13**	**13**
Expenditures for environmental loss contingencies	**(6)**	**(15)**	**(21)**
Balance, December 31, 2009[(a)]	**9**	**20**	**29**
Amount accrued for environmental loss contingencies	5	13	18
Expenditures for environmental loss contingencies	(6)	(18)	(24)
Balance, December 31, 2010[(a)]	**8**	**15**	**23**
Amount accrued for environmental loss contingencies	**1**	**8**	**9**
Expenditures for environmental loss contingencies	**(3)**	**(17)**	**(20)**
Balance, December 31, 2011[(a)]	**$ 6**	**$ 6**	**$ 12**

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

PROGRESS ENERGY

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

PEC

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

In 2004, the EPA advised PEC that it had been identified as a PRP at the Ward Transformer site located in Raleigh, N.C. (Ward) site. The EPA offered PEC and a number of other PRPs the opportunity to negotiate the removal action for the Ward site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the Ward site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the Ward site. At December 31, 2011 and December 31, 2010, PEC's recorded liability for the site was approximately $5 million. In 2008 and 2009, PEC filed civil actions against PRPs seeking contribution for and recovery of costs incurred in remediating the Ward site, as well as a declaratory judgment that defendants are jointly and severally liable for response costs at the site. PEC has settled with a number of the PRPs and is in active settlement negotiations with others. On March 24, 2010, the federal district court in which this matter is pending denied motions to dismiss filed by a number of defendants, but granted several other motions filed by state agencies and successor entities. The court established a "test case" program providing for a determination of liability on the part of a set of representative defendants. Summary judgment motions and responsive pleadings are being filed by and against these defendants and discovery and briefing will be completed by May 2012. Meanwhile, proceedings with respect to the other defendants have been stayed. The outcome of these matters cannot be predicted.

In 2008, the EPA issued a Record of Decision for the operable unit for stream segments downstream from the Ward site (Ward OU1) and advised 61 parties, including PEC, of their identification as PRPs for Ward OU1 and for further investigation at the Ward facility and certain adjacent areas (Ward OU2). The EPA's estimate for the selected remedy for Ward OU1 is approximately $6 million. The EPA offered PEC and the other PRPs the opportunity to negotiate implementation of a response action for Ward OU1 and a remedial investigation and feasibility study for Ward OU2, as well as reimbursement to the EPA of approximately $1 million for the EPA's past expenditures in addressing conditions at the site. On September 29, 2011, the EPA issued unilateral administrative orders to certain parties, which did not include PEC, directing the performance of remedial activities with regard to Ward OU1. It is not possible at this time to reasonably estimate the total amount of PEC's obligation, if any, for Ward OU1 and Ward OU2.

PEF

The accruals for PEF's MGP and other sites relate to two former MGP sites and other sites associated with PEF that have required, or are anticipated to require, investigation and/or remediation. The maximum amount of the range for all the sites cannot be determined at this time. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF has reviewed all distribution transformer sites and all substation sites for mineral oil-impacted soil caused by equipment integrity issues. Should additional distribution transformer sites be identified outside of this population, the distribution O&M costs will not be recoverable through the ECRC.

B. AIR AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations impacting air and water quality, which likely would result in increased capital expenditures and O&M expense. Control equipment installed for compliance with then-existing or proposed laws and regulations may address some of the issues outlined. PEC and PEF have been developing an integrated compliance strategy to meet these evolving requirements. PEC has installed environmental compliance controls that meet the emission reduction requirements under the first phase of the North Carolina Clean Smokestacks Act (Clean Smokestacks Act). The air quality controls installed to comply with nitrogen oxides (NOx) and sulfur dioxide (SO_2) requirements under certain sections of the Clean Air Act and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, largely address the CAIR requirements for NOx and SO_2 for our North Carolina units at PEC. PEF has installed environmental compliance controls that meet the emission reduction requirements under the first phase of the CAIR.

In 2008, the D.C. Court of Appeals vacated the Clean Air Mercury Rule (CAMR). As a result, the EPA subsequently announced that it would develop maximum achievable control technology (MACT) standards. The U.S. District Court for the District of Columbia issued an order requiring the EPA to issue a final MACT standard for power plants. On February 16, 2012, the EPA published the final MACT standards for coal-fired and oil-fired electric steam generating units (EGU MACT). The rule will become effective on April 16, 2012. Compliance is due in three years with provisions for a one-year extension from state agencies on a case-by-case basis. The EGU MACT contains stringent emission limits for mercury, non-mercury metals and acid gases from coal-fired units and hazardous air pollutant metals, acid gases and hydrogen fluoride from oil-fired units. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC is relatively well positioned to comply with the EGU MACT. However, PEF will be required to complete additional emissions controls and/or fleet modernization projects in order to meet the compliance timeframe for the EGU MACT. We are continuing to evaluate the impacts of the EGU MACT on the Utilities. We anticipate that compliance with the EGU MACT will satisfy the North Carolina mercury rule requirements for PEC. The outcome of these matters cannot be predicted.

The CAIR, issued by the EPA, required the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO_2 emissions. The CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2. States were required to adopt rules implementing the CAIR, and the EPA approved the North Carolina CAIR, the South Carolina CAIR and the Florida CAIR. A 2008 decision by the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) remanded the CAIR without vacating it for the EPA to conduct further proceedings.

On July 7, 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to replace the CAIR. The CSAPR, slated to take effect on January 1, 2012, contains new emissions trading programs for NOx and SO_2 emissions as well as more stringent overall emissions targets in 27 states, including North Carolina, South Carolina and Florida. A number of parties including groups which PEC and PEF are members of, filed petitions for reconsideration and stay of, as well as legal challenges to, the CSAPR. On December 30, 2011, the D.C. Court of Appeals issued an order staying the implementation of the CSAPR, pending a decision by the court resolving the challenges to the rule. Oral argument for the CSAPR litigation has been scheduled for April 13, 2012. As a result of the stay of CSAPR, the CAIR will remain in effect. The EPA issued the CSAPR as four separate programs, including the NOx annual trading program, the NOx ozone season trading program, the SO_2 Group 1 trading program and the SO_2 Group 2 trading program. If the CSAPR is upheld, North Carolina and South Carolina are included in the NOx and SO_2 annual trading programs, as well as the NOx ozone season program. North Carolina remains classified as a Group 1 state, which will require additional NOx and SO_2 emission reductions beginning in January 2014. South Carolina remains classified as a Group 2 state with no additional reductions required. Under the CSAPR, Florida is subject only to the NOx ozone season program. Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC and PEF are positioned to comply with the CSAPR without the need for significant capital expenditures. We cannot predict the outcome of this matter.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at Crystal River Units No. 4 and No. 5 (CR4 and CR5), which have both been completed and placed in service. Under an agreement with the FDEP, PEF will retire Crystal River Units No. 1 and No. 2 (CR1 and CR2) as coal-fired units and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was originally anticipated to be around 2020. As discussed in Note 8B, major construction activities for Levy are being postponed until after the NRC issues the Levy COL. As required, PEF has advised the FDEP of these developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated date. We are currently evaluating the impacts of the Levy schedule on PEF's compliance with environmental regulations. We cannot predict the outcome of this matter.

We account for emission allowances as inventory using the average cost method. Emission allowances are included on the Balance Sheets in inventory and in other assets and deferred debits. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. As previously discussed, the CSAPR establishes new NOx annual and seasonal ozone programs and a new SO_2 trading program. NOx and SO_2 emission allowances applicable to the current CAIR cannot be used to satisfy the new CSAPR programs. SO_2 emission allowances will be utilized by the Utilities to comply with existing Clean Air Act requirements. NOx allowances cannot be utilized to comply with other requirements. As a result of the previously discussed D.C. Court of Appeals order staying the implementation of the CSAPR, the CAIR emission allowance program remains in effect. At December 31, 2011 and December 31, 2010, PEC had an immaterial amount of NOx emission allowances. At December 31, 2011 and December 31, 2010, PEF had approximately \$22 million and \$28 million, respectively, in NOx emission allowances.

22. COMMITMENTS AND CONTINGENCIES

A. PURCHASE OBLIGATIONS

In most cases, our purchase obligation contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. At December 31, 2011, the following tables reflect contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2012	2013	2014	2015	2016	Thereafter	Total
Fuel[(a)]	$ 2,324	$ 2,053	$ 1,644	$ 1,460	$ 1,182	$ 6,437	$ 15,100
Purchased power	459	440	381	391	373	3,104	5,148
Construction obligations[(a)]	331	216	35	23	4	10	619
Other purchase obligations	153	100	69	61	71	603	1,057
Total	$ 3,267	$ 2,809	$ 2,129	$ 1,935	$ 1,630	$ 10,154	$ 21,924

PEC

(in millions)	2012	2013	2014	2015	2016	Thereafter	Total
Fuel	$ 1,173	$ 970	$ 760	$ 718	$ 626	$ 1,864	$ 6,111
Purchased power	79	70	64	70	68	376	727
Construction obligations	277	114	25	19	-	-	435
Other purchase obligations	77	44	47	30	38	242	478
Total	$ 1,606	$ 1,198	$ 896	$ 837	$ 732	$ 2,482	$ 7,751

PEF

(in millions)	2012	2013	2014	2015	2016	Thereafter	Total
Fuel[(a)]	$ 1,151	$ 1,083	$ 884	$ 742	$ 556	$ 4,573	$ 8,989
Purchased power	380	370	317	321	305	2,728	4,421
Construction obligations[(a)]	54	102	10	4	4	10	184
Other purchase obligations	64	48	22	31	33	361	559
Total	$ 1,649	$ 1,603	$ 1,233	$ 1,098	$ 898	$ 7,672	$ 14,153

(a) PEF signed an EPC agreement on December 31, 2008, with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two approximately 1,100-MW Westinghouse AP1000 nuclear units planned for construction at Levy. Due to uncertainty regarding the ultimate magnitude and timing of obligations under the EPC agreement and the Levy nuclear fabrication contract, the table includes only the obligations related to the selected components of long lead time equipment as discussed under "Fuel and Purchased Power" and "Construction Obligations."

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel as well as transportation agreements for the related fuel. Our purchases under these commitments were $2.697 billion, $2.890 billion and $2.921 billion for 2011, 2010 and 2009, respectively. PEC's purchases were $1.398 billion, $1.489 billion and $1.527 billion in 2011, 2010 and 2009, respectively. PEF's purchases were $1.299 billion, $1.401 billion and $1.394 billion in 2011, 2010 and 2009, respectively. Essentially all fuel and certain purchased power costs incurred by PEC and PEF are eligible for recovery through their respective cost-recovery clauses.

In December 2008, PEF entered into a nuclear fuel fabrication contract that contained exit provisions with termination fees for the planned Levy nuclear units. Due to revisions in the construction schedule and startup dates the nuclear fuel fabrication contract was terminated during 2011. (See discussion following under "Construction Obligations.")

Both PEC and PEF have ongoing purchased power contracts, including renewable energy contracts, with other utilities, certain co-generators and qualified facilities (QFs), with expiration dates ranging from 2012 to 2032. These purchased power contracts generally provide for capacity and energy payments or bundled capacity and energy payments. In addition, both PEC and PEF have various contracts to secure transmission rights. Our purchases under purchased power contracts, including transmission costs, were $925 million, $907 million and $756 million for 2011, 2010 and 2009, respectively. PEC's purchases, including transmission costs, were $253 million, $239 million and $171 million in 2011, 2010 and 2009, respectively. PEF's purchases, including transmission costs, were $672 million, $668 million and $585 million in 2011, 2010 and 2009, respectively.

PEC has executed certain firm contracts for approximately 985 MW of purchased power with other utilities, including tolling contracts, with expiration dates ranging from 2019 to 2022 and representing between 33 percent and 100 percent of plant net output. Minimum purchases under these contracts included in the previous table, representing capital-related capacity costs, are approximately $51 million, $52 million, $53 million, $60 million and $60 million for 2012 through 2016, respectively, and $271 million payable thereafter.

PEC has various pay-for-performance contracts with QFs, including renewable energy, for approximately 81 MW of firm capacity expiring at various times through 2032. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. Payments for both capacity and energy are contingent upon the QFs' ability to generate and, therefore, are not included in the previous table.

PEC has entered into conditional agreements for firm pipeline transportation capacity to support PEC's gas supply needs. Certain agreements are for the period from July 2012 through May 2033. The estimated total cost to PEC associated with these agreements is approximately $1.510 billion, approximately $380 million of which will be classified as a capital lease. Due to the conditions of the capital lease agreement, the capital lease will not be recorded on PEC's balance sheet until mid-2012. The transactions are subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related interstate and intrastate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in PEC's fuel commitments or in PEC's capital lease assets or obligations.

PEF has executed certain firm contracts for approximately 499 MW of purchased power with other utilities with expiration dates ranging from 2012 to 2016 and representing between 12 percent and 25 percent of plant net output. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $53 million, $46 million, $65 million, $65 million and $27 million for 2012 through 2016, respectively.

PEF has ongoing purchased power contracts with certain QFs for 682 MW of firm capacity with expiration dates ranging from 2012 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. All ongoing commitments have been approved by the FPSC. Minimum expected future capacity payments under these contracts are $313 million, $309 million, $238 million, $244 million and $273 million for 2012 through 2016, respectively, and $2.728 billion payable thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $507 million, $703 million and $818 million for 2011, 2010 and 2009, respectively.

PEC has purchase obligations related to various capital projects including new generation and transmission obligations. Total payments under PEC's construction-related contracts were $460 million, $555 million and $199 million for 2011, 2010 and 2009, respectively. Payments for 2011 primarily relate to construction of generating facilities at our sites in Wayne County, N.C., and New Hanover County, N.C., as discussed in Note 8B.

PEF has purchase obligations related to capital projects including Levy and various new generation, transmission and environmental compliance projects. Total payments under PEF's construction-related contracts were $47 million, $147 million and $619 million for 2011, 2010 and 2009, respectively, including $6 million, $63 million and $243 million for 2011, 2010 and 2009, respectively, toward long lead equipment and engineering related to the Levy EPC.

The future construction obligations presented in the previous tables for Progress Energy and PEF exclude PEF's Levy EPC agreement. The EPC agreement includes provisions for termination. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. As discussed in Note 8C, in 2010 PEF identified a schedule shift in the Levy project, and major construction activities on Levy have been postponed until after the NRC issues the COL for the plants, which is expected in 2013 if the current licensing schedule remains on track. We executed an amendment to the EPC agreement in 2010 due to the schedule shifts. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF completed vendor negotiations in July 2011 to continue or suspend purchase orders for long lead time equipment without material fees or charges. Prior to the EPC amendment, estimated payments and associated escalations were $8.608 billion for the multi-year contract and did not assume any joint ownership. Because we have executed an amendment to the EPC agreement and anticipate negotiating additional amendments upon receipt of the COL, we cannot currently predict when those obligations will be satisfied or the magnitude of any change. PEF has continued with selected components of long lead time equipment. Work was suspended on the remaining long lead time equipment items, which have total remaining estimated payments and associated escalations of approximately $1.250 billion included in the previously discussed $8.608 billion. We cannot predict the outcome of this matter.

OTHER PURCHASE OBLIGATIONS

We have various other contractual obligations primarily related to PESC service contracts for operational services, PEC service agreements related to its Smith Energy Complex, Wayne County, N.C., and New Hanover County, N.C., generating facilities, and PEF service agreements related to the Hines Energy Complex and the Bartow Plant. Our payments under these agreements were $151 million, $124 million and $56 million for 2011, 2010 and 2009, respectively.

PEC has various other purchase obligations, including obligations for long-term service agreements, parts and equipment, limestone supply and fleet vehicles. Total purchases under these contracts were $73 million, $55 million and $14 million for 2011, 2010 and 2009, respectively.

PEF has various other purchase obligations, including long-term service agreements for the Hines Energy Complex and the Bartow Plant. Total payments under these contracts were $54 million, $35 million and $22 million for 2011, 2010 and 2009, respectively. Future obligations are primarily comprised of the long-term service agreements.

B. LEASES

We and the Utilities lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Additionally, the Utilities have entered into certain purchased power agreements, which are classified as leases. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant.

Our rent expense under operating leases other than for purchased power totaled $42 million, $39 million and $37 million for 2011, 2010 and 2009, respectively. Our purchased power expense under agreements classified as operating leases was approximately $62 million, $61 million and $11 million in 2011, 2010 and 2009, respectively.

In 2003, we entered into an operating lease for a building for which minimum annual rental payments are approximately $7 million. The lease term expires July 2035 and provides for no rental payments during the last 15 years of the lease, during which period $53 million of rental expense will be recorded on the Consolidated Statements of Income. See Note 2 regarding our exit plan to vacate and sublease this building.

PEC's rent expense under operating leases other than for purchased power totaled $26 million, $25 million and $26 million during 2011, 2010 and 2009, respectively. These amounts include rent expense allocated from PESC to PEC of $5 million in 2011, 2010 and 2009.

PEC has entered into purchased power agreements that are classified as operating leases. These agreements, which have total minimum payments of approximately $512 million and expire through 2032, primarily relate to two tolling agreements for purchased power of approximately 576 MW (100 percent of net output). Purchased power expense under agreements classified as operating leases was approximately $62 million, $38 million and $11 million in 2011, 2010 and 2009, respectively.

PEF's rent expense under operating leases other than for purchased power totaled $15 million, $14 million and $11 million during 2011, 2010 and 2009, respectively. These amounts include rent expense allocated from PESC to PEF of $4 million in 2011 and $3 million in 2010 and 2009.

PEF has entered into a purchased power tolling agreement that is classified as an operating lease. This agreement for approximately 640 MW (100 percent of net output) has minimum annual payments beginning in June 2012 and expires in 2027 with total minimum payments of approximately $421 million. Purchased power expense under agreements classified as operating leases was approximately $23 million in 2010. PEF had no purchased power expense under operating lease agreements in 2011 and 2009.

PEF has a capital lease for a building and one tolling agreement for purchased power, which is classified as a capital lease of the related plant. PEF entered into the agreement for the building in 2005 and the lease term expires in 2047. The agreement for the building provides for minimum annual payments from 2007 through 2026 and no payments from 2027 through 2047. The minimum annual payments are approximately $5 million, for a total of approximately $103 million. During the last 20 years of the building lease, approximately $51 million of rental expense will be recorded on the Statements of Income. The 517-MW (100 percent of net output) tolling agreement for purchased power has minimum annual payments of approximately $21 million from 2007 through 2024, for a total of approximately $348 million.

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

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Buildings	**$ 267**	$ 267	**$ 30**	$ 30	**$ 237**	$ 237
Less: Accumulated amortization	**(56)**	(46)	**(18)**	(17)	**(38)**	(29)
Total	**$ 211**	$ 221	**$ 12**	$ 13	**$ 199**	$ 208

Consistent with the ratemaking treatment for capital leases, capital lease expenses are charged to the same accounts that would be used if the leases were operating leases. Thus, our and the Utilities' capital lease expense is generally included in O&M or purchased power expense. Our capital lease expense totaled $25 million, $25 million and $26 million for 2011, 2010 and 2009, respectively, which was primarily comprised of PEF's capital lease expense of $23 million, $23 million and $24 million for 2011, 2010 and 2009, respectively.

At December 31, 2011, minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable operating and capital leases were:

	Progress Energy		PEC		PEF	
(in millions)	Capital	Operating	Capital	Operating	Capital	Operating
2012	$ 28	$ 61	$ 2	$ 28	$ 26	$ 27
2013	36	85	10	43	26	36
2014	26	82	-	42	26	35
2015	26	79	-	43	26	34
2016	25	79	-	43	25	34
Thereafter	201	791	6	472	195	318
Minimum annual payments	342	1,177	18	671	324	484
Less amount representing imputed interest	(131)		(6)		(125)	
Total	$ 211	$ 1,177	$ 12	$ 671	$ 199	$ 484

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's rents received are primarily contingent upon usage and totaled $35 million, $33 million, and $34 million for 2011, 2010 and 2009, respectively. PEC's minimum rentals receivable under noncancelable leases are $12 million for 2012 and none thereafter. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $86 million, $85 million and $84 million for 2011, 2010 and 2009, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2012 and thereafter.

C. GUARANTEES

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2011, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included on the accompanying Balance Sheets.

At December 31, 2011, we have issued guarantees and indemnifications of and for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses. At December 31, 2011, our estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $337 million, including $61 million at PEF. Related to the sales of businesses, the latest specified notice period extends until 2013 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications related to discontinued operations have no limitations as to time or maximum potential future payments. As part of settlement agreements entered into in 2002, PEF is responsible for providing the joint owners of CR3 a specified amount of generating capacity through the expiration of the indemnification provisions of the joint owner agreement in 2013. Due to the CR3 outage (See Note 8C), PEF has been unable to meet the required generating capacity and has provided replacement power from other generation sources or purchased power. During the year ended December 31, 2011, we and PEF recorded indemnification charges totaling $48 million for estimated joint owner replacement power costs for 2011 and future years, and provided replacement power totaling $21 million. At December 31, 2011 and 2010, we had recorded liabilities related to guarantees and indemnifications to third parties of $63 million and $31 million, respectively. These amounts included $37 million and $6 million for PEF at December 31, 2011 and 2010, respectively. As current estimates change, additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

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

D. OTHER COMMITMENTS AND CONTINGENCIES

MERGER

During January and February 2011, Progress Energy and its directors were named as defendants in 11 purported class action lawsuits with 10 lawsuits brought in the Superior Court, Wake County, N.C., and one lawsuit filed in the United States District Court for the Eastern District of North Carolina, each in connection with the Merger (we refer to these lawsuits as the "actions"). The complaints in the actions alleged, among other things, that the Merger Agreement was the product of breaches of fiduciary duty by the individual defendants, in that it allegedly did not provide for full and fair value for Progress Energy's shareholders; that the Merger Agreement contained coercive deal protection measures; and that the Merger Agreement and the Merger were approved as a result, allegedly, of improper self-dealing by certain defendants who would receive certain alleged employment compensation benefits and continued employment pursuant to the Merger Agreement. The complaints in the actions also alleged that Progress Energy aided and abetted the individual defendants' alleged breaches of fiduciary duty. As relief, the plaintiffs in the actions sought, among other things, to enjoin completion of the Merger.

Additionally, the complaint in the federal action was amended in early April 2011 to include allegations that the defendants violated federal securities laws in connection with statements contained in the registration statement filed on Form S-4 by Duke Energy related to the Merger (the Registration Statement).

On March 31, 2011, counsel for the federal action plaintiff sent a derivative demand letter to Mr. William D. Johnson, Chairman, President and CEO of Progress Energy, demanding that the Progress Energy board of directors desist from moving forward with the Merger, make certain disclosures and engage in an auction of the company. Also on March 31, 2011, the same counsel sent Mr. Johnson a substantially identical derivative demand letter on behalf of two other purported Progress Energy shareholders.

On April 13, 2011, counsel for the federal action plaintiff sent another derivative demand letter to Mr. Johnson further demanding that the Progress Energy board of directors desist from moving forward with the Merger unless certain changes are made to the Merger Agreement and additional disclosures are made. Also on April 13, 2011, the same counsel sent Mr. Johnson a substantially identical derivative demand letter on behalf of two other purported Progress Energy shareholders.

On April 25, 2011, the Progress Energy board of directors established a special committee of disinterested directors to conduct a review and evaluation of the allegations and legal claims set forth in the derivative demand letters. The special committee investigated the allegations and legal claims and determined there was no basis to pursue the claims.

By order dated June 17, 2011, the court consolidated the state court cases. On June 21, 2011, the plaintiffs in the state court actions filed a verified consolidated amended complaint in the consolidated state court actions alleging breach of fiduciary duty by the individual defendants, and that Progress Energy aided and abetted the individual defendants' alleged breaches of fiduciary duty. The verified consolidated amended complaint further alleged that the Registration Statement and amendments filed on April 8, April 25, and May 13, 2011, failed to disclose material facts, giving rise to plaintiffs' claims.

On July 11, 2011, solely to avoid the costs, risks and uncertainties inherent in litigation and to allow its shareholders to vote on the proposals required in connection with the Merger at its special meeting of its shareholders, Progress Energy entered into a memorandum of understanding with plaintiffs in the consolidated state court actions and other named defendants to settle the consolidated action and all related claims that were or could have been asserted in other actions, subject to court approval. The details of the settlement were set forth in a notice sent to Progress Energy's shareholders of record that were members of the class as of July 5, 2011.

On November 29, 2011, the court entered a final order and judgment approving the settlement as fair, reasonable and adequate and awarded legal fees and expenses to plaintiffs' counsel of $550,000. The court dismissed the action with prejudice and released and fully discharged all claims, including federal claims, which had been or could be in the future asserted in the action or in any court, tribunal or proceeding. On December 8, 2011, the federal action was voluntarily dismissed.

ENVIRONMENTAL

We are subject to federal, state and local regulations regarding environmental matters (See Note 21).

Hurricane Katrina

In May 2011, PEC and PEF were named in a class action lawsuit filed in the U.S. District Court for the Southern District of Mississippi. Plaintiffs claim that PEC and PEF, along with numerous other utility, oil, coal and chemical companies, are liable for damages relating to losses suffered by victims of Hurricane Katrina. Plaintiffs claim that defendants' greenhouse gas emissions contributed to the frequency and intensity of storms such as Hurricane Katrina. We believe the plaintiffs' claim is without merit; however, we cannot predict the outcome of this matter.

Water Discharge Permit

On October 5, 2011, Earthjustice, on behalf of the Sierra Club and Florida Wildlife Federation, filed a petition seeking review of the water discharge permit issued to CR1, CR2 and CR3 raising a number of technical and legal issues with respect to the permit. A settlement has been tentatively reached providing for the withdrawal of the petition and issuance of a revised water discharge permit identical in form to the one under appeal but with an 18 month term. The current permit has a five year term. The settlement, if finalized, will fully resolve the current dispute. We cannot predict the outcome of this matter.

SPENT NUCLEAR FUEL MATTERS

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

The DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, the Utilities filed a complaint in the U.S. Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from our various facilities on or before January 31, 1998. The Utilities have asserted over $90 million in damages incurred between January 31, 1998, and December 31, 2005, the time period set by the court for damages in this case.

On June 14, 2011, the judge in the U.S. Court of Federal Claims issued a ruling to award the Utilities substantially all their asserted damages. In September 2011, after the government dismissed its notice of appeal, the judgment became final. As a result, in September 2011, PEC recorded the $92 million award as an offset for past spent fuel storage costs incurred, of which $27 million was O&M expense. PEC received the cash award in January 2012.

On December 12, 2011, the Utilities filed another complaint in the U.S. Court of Federal Claims against the DOE, claiming damages incurred from January 1, 2006, through December 31, 2010. The damages stem from the same breach of contract asserted in the previous litigation. The Utilities may file subsequent damage claims as they incur additional costs. We cannot predict the outcome of this matter.

SYNTHETIC FUELS MATTERS

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates arising out of an Asset Purchase Agreement dated as of October 19, 1999, and amended as of August 23, 2000 (the Asset Purchase Agreement), by and among U.S. Global, LLC (Global); Earthco; certain affiliates of Earthco; EFC Synfuel LLC (which was owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (renamed Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to the Asset Purchase Agreement. In a case filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case), Global requested an unspecified amount of compensatory damages, as well as declaratory relief. Global asserted (1) that pursuant to the Asset Purchase Agreement, it was entitled to an interest in two synthetic fuels facilities previously owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities and (2) that it was entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities. As a result of the expiration of the Section 29 tax credit program on December 31, 2007, all of our synthetic fuels businesses were abandoned and we reclassified our synthetic fuels businesses as discontinued operations.

The jury awarded Global $78 million. On October 23, 2009, Global filed a motion to assess prejudgment interest on the award. On November 20, 2009, the court granted the motion and assessed $55 million in prejudgment interest and entered judgment in favor of Global in a total amount of $133 million. During the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations. On December 18, 2009, we appealed the Broward County judgment to the Florida Fourth District Court of Appeals. Also in December 2009, we made a $154 million payment, which represents payment of the total judgment and a required premium equivalent to two years of interest, to the Broward County Clerk of Court bond account. The appellate briefing process has been completed. Oral argument was held on September 27, 2011. We cannot predict the outcome of this matter.

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

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

Affiliates appealed the superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal. Based upon the verdict in the Florida Global Case, we anticipate dismissal of the North Carolina Global Case.

CLAIM OF HOLDER OF CONTINGENT VALUE OBLIGATIONS

On June 10, 2011, Davidson Kempner Partners, M.H. Davidson & Co., Davidson Kempner Institutional Partners, L.P., and Davidson Kempner International, Ltd. (jointly, Davidson Kempner) filed a lawsuit against us in the Supreme Court of the State of New York, County of New York. Davidson Kempner is a holder of CVOs (See Note 16) and alleged that we improperly deducted escrow deposits in 2005 in determining net after-tax cash flow under the agreement governing the CVOs and that by taking this position, we breached our obligation under the agreement to exercise good faith and fair dealing. The plaintiffs alleged that this breach caused injury to the holders of CVOs in the approximate amount of $42 million. The plaintiffs requested declaratory judgment to require that we deduct the escrowed payments in 2006.

On August 2, 2011, the parties filed a Stipulation of Discontinuance without Prejudice to dismiss the state lawsuit so that certain of the plaintiffs could file a federal lawsuit against us. On August 9, 2011, M.H. Davidson & Co. and Davidson Kempner International, Ltd. filed a lawsuit against us in the United States District Court for the Southern District of New York with the same allegations and seeking the same relief as the prior state lawsuit. On October 3, 2011, we entered a settlement agreement and release with Davidson Kempner under which the parties mutually released all claims related to the CVOs and we purchased all of Davidson Kempner's CVOs at a negotiated purchase price of $0.75 per CVO. The parties to the federal lawsuit filed a Stipulation of Discontinuance with Prejudice dismissing the lawsuit on October 12, 2011.

OTHER LITIGATION MATTERS

We and our subsidiaries are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, we have made accruals and disclosures to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

23. CONDENSED CONSOLIDATING STATEMENTS

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

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

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

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. At December 31, 2011, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional, and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances, and as disclosed in Note 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a variable-interest entity of which we are not the primary beneficiary. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

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

Condensed Consolidating Statement of Income
Year ended December 31, 2011

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$ -	$ 4,379	$ 4,528	$ -	$ 8,907
Affiliate revenues	-	-	272	(272)	-
Total operating revenues	-	4,379	4,800	(272)	8,907
Operating expenses					
Fuel used in electric generation	-	1,506	1,387	-	2,893
Purchased power	-	778	315	-	1,093
Operation and maintenance	10	881	1,407	(262)	2,036
Depreciation, amortization and accretion	-	169	532	-	701
Taxes other than on income	-	350	218	(6)	562
Other	-	(1)	35	-	34
Total operating expenses	10	3,683	3,894	(268)	7,319
Operating (loss) income	(10)	696	906	(4)	1,588
Other income (expense)					
Interest income	-	1	2	(1)	2
Allowance for equity funds used during construction	-	32	71	-	103
Other, net	(61)	5	(4)	2	(58)
Total other (expense) income, net	(61)	38	69	1	47
Interest charges					
Interest charges	279	276	205	-	760
Allowance for borrowed funds used during construction	-	(14)	(21)	-	(35)
Total interest charges, net	279	262	184	-	725
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(350)	472	791	(3)	910
Income tax (benefit) expense	(127)	170	275	5	323
Equity in earnings of consolidated subsidiaries	798	-	-	(798)	-
Income from continuing operations	575	302	516	(806)	587
Discontinued operations, net of tax	-	(3)	(2)	-	(5)
Net income	575	299	514	(806)	582
Net income attributable to noncontrolling interests, net of tax	-	(4)	-	(3)	(7)
Net income attributable to controlling interests	$ 575	$ 295	$ 514	$ (809)	$ 575

Condensed Consolidating Statement of Income
Year ended December 31, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$ -	$ 5,268	$ 4,922	$ -	$ 10,190
Affiliate revenues	-	-	248	(248)	-
Total operating revenues	-	5,268	5,170	(248)	10,190
Operating expenses					
Fuel used in electric generation	-	1,614	1,686	-	3,300
Purchased power	-	977	302	-	1,279
Operation and maintenance	7	912	1,345	(237)	2,027
Depreciation, amortization and accretion	-	426	494	-	920
Taxes other than on income	-	362	225	(7)	580
Other	-	17	13	-	30
Total operating expenses	7	4,308	4,065	(244)	8,136
Operating (loss) income	(7)	960	1,105	(4)	2,054
Other income (expense)					
Interest income	7	2	5	(7)	7
Allowance for equity funds used during construction	-	28	64	-	92
Other, net	(1)	1	(3)	3	-
Total other income, net	6	31	66	(4)	99
Interest charges					
Interest charges	282	293	211	(7)	779
Allowance for borrowed funds used during construction	-	(13)	(19)	-	(32)
Total interest charges, net	282	280	192	(7)	747
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(283)	711	979	(1)	1,406
Income tax (benefit) expense	(111)	267	378	5	539
Equity in earnings of consolidated subsidiaries	1,027	-	-	(1,027)	-
Income from continuing operations	855	444	601	(1,033)	867
Discontinued operations, net of tax	1	(1)	(4)	-	(4)
Net income	856	443	597	(1,033)	863
Net (income) loss attributable to noncontrolling interests, net of tax	-	(4)	1	(4)	(7)
Net income attributable to controlling interests	$ 856	$ 439	$ 598	$ (1,037)	$ 856

Condensed Consolidating Statement of Income
Year ended December 31, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$ -	$ 5,259	$ 4,626	$ -	$ 9,885
Affiliate revenues	-	-	235	(235)	-
Total operating revenues	-	5,259	4,861	(235)	9,885
Operating expenses					
Fuel used in electric generation	-	2,072	1,680	-	3,752
Purchased power	-	682	229	-	911
Operation and maintenance	8	839	1,269	(222)	1,894
Depreciation, amortization and accretion	-	502	484	-	986
Taxes other than on income	-	347	216	(6)	557
Other	-	13	-	-	13
Total operating expenses	8	4,455	3,878	(228)	8,113
Operating (loss) income	(8)	804	983	(7)	1,772
Other income (expense)					
Interest income	10	5	9	(10)	14
Allowance for equity funds used during construction	-	91	33	-	124
Other, net	18	6	(22)	4	6
Total other income, net	28	102	20	(6)	144
Interest charges					
Interest charges	233	280	215	(10)	718
Allowance for borrowed funds used during construction	-	(27)	(12)	-	(39)
Total interest charges, net	233	253	203	(10)	679
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(213)	653	800	(3)	1,237
Income tax (benefit) expense	(93)	200	286	4	397
Equity in earnings of consolidated subsidiaries	875	-	-	(875)	-
Income from continuing operations	755	453	514	(882)	840
Discontinued operations, net of tax	2	(43)	(38)	-	(79)
Net income	757	410	476	(882)	761
Net (income) loss attributable to noncontrolling interests, net of tax	-	(3)	2	(3)	(4)
Net income attributable to controlling interests	$ 757	$ 407	$ 478	$ (885)	$ 757

Condensed Consolidating Balance Sheet
December 31, 2011

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$ -	$ 10,523	$ 11,887	$ 87	$ 22,497
Current assets					
Cash and cash equivalents	117	92	21	-	230
Receivables, net	-	372	517	-	889
Notes receivable from affiliated companies	53	-	219	(272)	-
Regulatory assets	-	244	31	-	275
Derivative collateral posted	-	123	24	-	147
Prepayments and other current assets	128	852	1,049	(87)	1,942
Total current assets	298	1,683	1,861	(359)	3,483
Deferred debits and other assets					
Investment in consolidated subsidiaries	14,043	-	-	(14,043)	-
Regulatory assets	-	1,602	1,423	-	3,025
Goodwill	-	-	-	3,655	3,655
Nuclear decommissioning trust funds	-	559	1,088	-	1,647
Other assets and deferred debits	140	242	856	(486)	752
Total deferred debits and other assets	14,183	2,403	3,367	(10,874)	9,079
Total assets	$ 14,481	$ 14,609	$ 17,115	$ (11,146)	$ 35,059
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$ 10,021	$ 4,728	$ 5,646	$ (10,374)	$ 10,021
Noncontrolling interests	-	4	-	-	4
Total equity	10,021	4,732	5,646	(10,374)	10,025
Preferred stock of subsidiaries	-	34	59	-	93
Long-term debt, affiliate	-	309	-	(36)	273
Long-term debt, net	3,543	4,482	3,693	-	11,718
Total capitalization	13,564	9,557	9,398	(10,410)	22,109
Current liabilities					
Current portion of long-term debt	450	-	500	-	950
Short-term debt	250	233	188	-	671
Notes payable to affiliated companies	-	238	34	(272)	-
Derivative liabilities	38	268	130	-	436
Other current liabilities	161	839	1,112	(84)	2,028
Total current liabilities	899	1,578	1,964	(356)	4,085
Deferred credits and other liabilities					
Noncurrent income tax liabilities	-	837	1,976	(458)	2,355
Regulatory liabilities	-	1,071	1,543	86	2,700
Other liabilities and deferred credits	18	1,566	2,234	(8)	3,810
Total deferred credits and other liabilities	18	3,474	5,753	(380)	8,865
Total capitalization and liabilities	$ 14,481	$ 14,609	$ 17,115	$ (11,146)	$ 35,059

Condensed Consolidating Balance Sheet
December 31, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$ -	$ 10,189	$ 10,961	$ 90	$ 21,240
Current assets					
Cash and cash equivalents	110	270	231	-	611
Receivables, net	-	497	536	-	1,033
Notes receivable from affiliated companies	14	48	115	(177)	-
Regulatory assets	-	105	71	-	176
Derivative collateral posted	-	140	24	-	164
Prepayments and other current assets	30	751	984	(273)	1,492
Total current assets	154	1,811	1,961	(450)	3,476
Deferred debits and other assets					
Investment in consolidated subsidiaries	14,316	-	-	(14,316)	-
Regulatory assets	-	1,387	987	-	2,374
Goodwill	-	-	-	3,655	3,655
Nuclear decommissioning trust funds	-	554	1,017	-	1,571
Other assets and deferred debits	75	238	894	(469)	738
Total deferred debits and other assets	14,391	2,179	2,898	(11,130)	8,338
Total assets	$ 14,545	$ 14,179	$ 15,820	$ (11,490)	$ 33,054
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$ 10,023	$ 4,957	$ 5,686	$ (10,643)	$ 10,023
Noncontrolling interests	-	4	-	-	4
Total equity	10,023	4,961	5,686	(10,643)	10,027
Preferred stock of subsidiaries	-	34	59	-	93
Long-term debt, affiliate	-	309	-	(36)	273
Long-term debt, net	3,989	4,182	3,693	-	11,864
Total capitalization	14,012	9,486	9,438	(10,679)	22,257
Current liabilities					
Current portion of long-term debt	205	300	-	-	505
Notes payable to affiliated companies	-	175	3	(178)	-
Derivative liabilities	18	188	53	-	259
Other current liabilities	278	1,002	1,184	(273)	2,191
Total current liabilities	501	1,665	1,240	(451)	2,955
Deferred credits and other liabilities					
Noncurrent income tax liabilities	3	528	1,608	(443)	1,696
Regulatory liabilities	-	1,084	1,461	90	2,635
Other liabilities and deferred credits	29	1,416	2,073	(7)	3,511
Total deferred credits and other liabilities	32	3,028	5,142	(360)	7,842
Total capitalization and liabilities	$ 14,545	$ 14,179	$ 15,820	$ (11,490)	$ 33,054

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2011

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 756	$ 706	$ 1,251	$ (1,098)	$ 1,615
Investing activities					
Gross property additions	-	(818)	(1,248)	-	(2,066)
Nuclear fuel additions	-	(15)	(211)	-	(226)
Purchases of available-for-sale securities and other investments	-	(4,438)	(579)	-	(5,017)
Proceeds from available-for-sale securities and other investments	-	4,441	529	-	4,970
Changes in advances to affiliated companies	(38)	48	(104)	94	-
Contributions to consolidated subsidiaries	(11)	-	-	11	-
Other investing activities	(24)	121	29	1	127
Net cash used by investing activities	(73)	(661)	(1,584)	106	(2,212)
Financing activities					
Issuance of common stock, net	53	-	-	-	53
Dividends paid on common stock	(734)	-	-	-	(734)
Dividends paid to parent	-	(513)	(585)	1,098	-
Net decrease in short-term debt	250	233	185	(1)	667
Proceeds from issuance of long-term debt, net	495	296	495	-	1,286
Retirement of long-term debt	(700)	(300)	-	-	(1,000)
Changes in advances from affiliated companies	-	63	31	(94)	-
Contributions from parent	-	10	1	(11)	-
Other financing activities	(40)	(12)	(4)	-	(56)
Net cash (used) provided by financing activities	(676)	(223)	123	992	216
Net increase (decrease) in cash and cash equivalents	7	(178)	(210)	-	(381)
Cash and cash equivalents at beginning of year	110	270	231	-	611
Cash and cash equivalents at end of year	$ 117	$ 92	$ 21	$ -	$ 230

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 16	$ 1,181	$ 1,562	$ (222)	$ 2,537
Investing activities					
Gross property additions	-	(1,014)	(1,231)	24	(2,221)
Nuclear fuel additions	-	(38)	(183)	-	(221)
Purchases of available-for-sale securities and other investments	-	(6,391)	(618)	-	(7,009)
Proceeds from available-for-sale securities and other investments	-	6,395	595	-	6,990
Changes in advances to affiliated companies	15	(2)	188	(201)	-
Return of investment in consolidated subsidiaries	54	-	-	(54)	-
Contributions to consolidated subsidiaries	(171)	-	-	171	-
Other investing activities	113	60	3	(115)	61
Net cash provided (used) by investing activities	11	(990)	(1,246)	(175)	(2,400)
Financing activities					
Issuance of common stock, net	434	-	-	-	434
Dividends paid on common stock	(717)	-	-	-	(717)
Dividends paid to parent	-	(102)	(100)	202	-
Dividends paid to parent in excess of retained earnings	-	-	(54)	54	-
Net decrease in short-term debt	(140)	-	-	-	(140)
Proceeds from issuance of long-term debt, net	-	591	-	-	591
Retirement of long-term debt	(100)	(300)	-	-	(400)
Changes in advances from affiliated companies	-	(201)	-	201	-
Contributions from parent	-	33	152	(185)	-
Other financing activities	-	(14)	(130)	125	(19)
Net cash (used) provided by financing activities	(523)	7	(132)	397	(251)
Net (decrease) increase in cash and cash equivalents	(496)	198	184	-	(114)
Cash and cash equivalents at beginning of year	606	72	47	-	725
Cash and cash equivalents at end of year	$ 110	$ 270	$ 231	$ -	$ 611

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 108	$ 1,079	$ 1,282	$ (198)	$ 2,271
Investing activities					
Gross property additions	-	(1,449)	(858)	12	(2,295)
Nuclear fuel additions	-	(78)	(122)	-	(200)
Proceeds from sales of assets to affiliated companies	-	-	11	(11)	-
Purchases of available-for-sale securities and other investments	-	(1,548)	(802)	-	(2,350)
Proceeds from available-for-sale securities and other investments	-	1,558	756	-	2,314
Changes in advances to affiliated companies	4	(2)	(172)	170	-
Return of investment in consolidated subsidiaries	12	-	-	(12)	-
Contributions to consolidated subsidiaries	(688)	-	-	688	-
Other investing activities	-	-	(1)	-	(1)
Net cash used by investing activities	(672)	(1,519)	(1,188)	847	(2,532)
Financing activities					
Issuance of common stock, net	623	-	-	-	623
Dividends paid on common stock	(693)	-	-	-	(693)
Dividends paid to parent	-	(1)	(200)	201	-
Dividends paid to parent in excess of retained earnings	-	-	(12)	12	-
Payments of short-term debt with original maturities greater than 90 days	(629)	-	-	-	(629)
Net increase (decrease) in short-term debt	100	(371)	(110)	-	(381)
Proceeds from issuance of long-term debt, net	1,683	-	595	-	2,278
Retirement of long-term debt	-	-	(400)	-	(400)
Changes in advances from affiliated companies	-	170	-	(170)	-
Contributions from parent	-	653	49	(702)	-
Other financing activities	(2)	(12)	12	10	8
Net cash provided (used) by financing activities	1,082	439	(66)	(649)	806
Net increase (decrease) in cash and cash equivalents	518	(1)	28	-	545
Cash and cash equivalents at beginning of year	88	73	19	-	180
Cash and cash equivalents at end of year	$ 606	$ 72	$ 47	$ -	$ 725

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data was as follows:

PROGRESS ENERGY

(in millions except per share data)	First	Second	Third	Fourth
2011				
Operating revenues	**$ 2,167**	**$ 2,256**	**$ 2,747**	**$ 1,737**
Operating income	**451**	**428**	**690**	**19**
Income (loss) from continuing operations	**187**	**180**	**293**	**(73)**
Net income (loss)	**185**	**178**	**293**	**(74)**
Net income (loss) attributable to controlling interests	**184**	**176**	**291**	**(76)**
Common stock data				
Basic and diluted earnings per common share				
Income (loss) from continuing operations attributable to controlling interests, net of tax	**0.63**	**0.60**	**0.98**	**(0.25)**
Net income (loss) attributable to controlling interests	**0.62**	**0.60**	**0.98**	**(0.25)**
Dividends declared per common share	**0.620**	**0.620**	**0.620**	**0.259**
Market price per share				
High	**46.83**	**49.03**	**52.42**	**56.33**
Low	**42.55**	**45.20**	**42.05**	**49.37**
2010				
Operating revenues	$ 2,535	$ 2,372	$ 2,962	$ 2,321
Operating income	494	440	753	367
Income from continuing operations	191	181	365	130
Net income	190	180	365	128
Net income attributable to controlling interests	190	180	361	125
Common stock data				
Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	0.67	0.62	1.23	0.43
Net income attributable to controlling interests	0.67	0.62	1.23	0.42
Dividends declared per common share	0.620	0.620	0.620	0.620
Market price per share				
High	41.35	40.69	44.82	45.61
Low	37.04	37.13	38.96	43.08

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. Typically, weather conditions in our service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to our customers. As a result, our overall operating results may fluctuate substantially on a seasonal basis.

In the third quarter of 2011, we determined the fair value of the CVOs based on the purchase price in a negotiated settlement agreement. As a result, we recognized $50 million of expense, net of tax, related to the change in the CVOs' fair market value. See Note 16 for additional information.

During the fourth quarter of 2011, we recorded $288 million to be refunded to customers through the fuel clause in accordance with the 2012 settlement agreement. This was recognized as a reduction in operating revenues. See Note 8C for additional information.

PEC

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2011				
Operating revenues	**$ 1,133**	**$ 1,060**	**$ 1,332**	**$ 1,003**
Operating income	**228**	**192**	**329**	**136**
Net income	**131**	**107**	**199**	**79**
Net income attributable to controlling interests	**131**	**107**	**199**	**79**
2010				
Operating revenues	$ 1,263	$ 1,117	$ 1,414	$ 1,128
Operating income	266	196	402	207
Net income	136	111	236	119
Net income attributable to controlling interests	138	112	234	119

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. Typically, weather conditions in PEC's service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to its customers. As a result, its overall operating results may fluctuate substantially on a seasonal basis.

PEF

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2011				
Operating revenues	**$ 1,032**	**$ 1,193**	**$ 1,414**	**$ 730**
Operating income (loss)	**216**	**234**	**361**	**(113)**
Net income (loss)	**102**	**113**	**203**	**(104)**
2010				
Operating revenues	$ 1,270	$ 1,252	$ 1,543	$ 1,189
Operating income	222	244	344	149
Net income	102	119	180	52

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. Typically, weather conditions in PEF's service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to its customers. As a result, its overall operating results may fluctuate substantially on a seasonal basis.

During the fourth quarter of 2011, PEF recorded $288 million to be refunded to customers through the fuel clause in accordance with the 2012 settlement agreement. This was recognized as a reduction in operating revenues. See Note 8C for additional information.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

PROGRESS ENERGY

DISCLOSURE CONTROLS AND PROCEDURES

Pursuant to the Securities Exchange Act of 1934, we carried out an evaluation, with the participation of management, including our Chairman, President and Chief Executive Officer and Chief Financial Officer, of the effectiveness of our 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, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information we are required to disclose in the reports that we file or submit 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 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 15d-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 accounting principles generally accepted 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 accounting principles generally accepted 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 at December 31, 2011. 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. 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 and Corporate Performance Committee (Audit Committee) of the board of directors.

Based on our assessment, management determined that, at December 31, 2011, Progress Energy maintained effective internal control over financial reporting.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the internal control over financial reporting of Progress Energy as of December 31, 2011, as stated in their report, which is included below.

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, 2011, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Progress Energy, Inc. and Subsidiaries (the "Company") as of December 31, 2011, based on 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, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, 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 and consolidated financial statement schedule as of and for the year ended December 31, 2011 of the Company and our report dated February 28, 2012 expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2012

PEC

DISCLOSURE CONTROLS AND PROCEDURES

Pursuant to the Securities Exchange Act of 1934, PEC carried out an evaluation, with the participation of its management, including PEC's 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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of PEC's management to establish and maintain adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. PEC'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 accounting principles generally accepted 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 PEC; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America; (3) provide reasonable assurance that receipts and expenditures of PEC are being made only in accordance with authorizations of management and directors of PEC; and (4) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PEC'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 PEC's internal control over financial reporting at December 31, 2011. 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. Management's assessment included an evaluation of the design of PEC'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, at December 31, 2011, PEC maintained effective internal control over financial reporting.

This annual report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting for PEC. As PEC is a non-accelerated filer, management's report is not subject to attestation by our independent registered public accounting firm pursuant to Section 404(c) of the Sarbanes-Oxley Act of 2002.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There has been no change in PEC's internal control over financial reporting during the quarter ended December 31, 2011, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

PEF

DISCLOSURE CONTROLS AND PROCEDURES

Pursuant to the Securities Exchange Act of 1934, PEF carried out an evaluation, with the participation of its management, including PEF's Chief Executive Officer and Chief Financial Officer, of the effectiveness of PEF'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, PEF'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 PEF 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 PEF'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 PEF's management to establish and maintain adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. PEF'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 accounting principles generally accepted 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 PEF; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America; (3) provide reasonable assurance that receipts and expenditures of PEF are being made only in accordance with authorizations of management and directors of PEF; and (4) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PEF'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 PEF's internal control over financial reporting at December 31, 2011. 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. Management's assessment included an evaluation of the design of PEF'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, at December 31, 2011, PEF maintained effective internal control over financial reporting.

This annual report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting for PEF. As PEF is a non-accelerated filer, management's report is not subject to attestation by our independent registered public accounting firm pursuant to Section 404(c) of the Sarbanes-Oxley Act of 2002.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There has been no change in PEF's internal control over financial reporting during the quarter ended December 31, 2011, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

a) Information regarding Progress Energy's directors and PEC's directors will be set forth in Progress Energy's and PEC's definitive proxy statements for the 2012 Annual Meetings of Shareholders or will be filed with the SEC as part of an amendment to the Annual Report on Form 10-K/A within 120 days after the end of our fiscal year and is incorporated by reference herein.

b) Information regarding both Progress Energy's and PEC's executive officers is set forth in PART I and is incorporated by reference herein.

c) We have adopted a Code of Ethics that applies to all of our employees, including our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and Controller (or persons performing similar functions). Our board of directors has adopted our Code of Ethics as its own standard. Board members, Progress Energy officers and Progress Energy employees certify their compliance with the Code of Ethics on an annual basis. Our Code of Ethics is posted on our website at www.progress-energy.com/investor and is available in print at no cost to any shareholder upon written request.

We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K relating to amendments to or waivers from any provision of the Code of Ethics applicable to our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and Controller by posting such information on our website cited above.

d) Information regarding the Audit and Corporate Performance Committee of Progress Energy's board of directors is set forth in Progress Energy's definitive proxy statement for the 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

PEC does not have a separate audit committee. Information regarding the responsibilities of the Audit and Corporate Performance Committee of Progress Energy's board with respect to PEC is set forth in PEC's definitive proxy statement for the 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

e) The board of directors has determined that Carlos A. Saladrigas and Theresa M. Stone are the "Audit Committee Financial Experts," as that term is defined in the rules promulgated by the SEC pursuant to the Sarbanes-Oxley Act of 2002, and have designated them as such. Both Mr. Saladrigas and Ms. Stone are "independent," as that term is defined in the general independence standards of the New York Stock Exchange listing standards.

f) Information regarding our compliance with Section 16(a) of the Securities Exchange Act of 1934 and certain corporate governance matters is set forth in Progress Energy's and PEC's definitive proxy statements for the 2012 Annual Meeting of Shareholders or will be filed as part of amendments to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

g) The following are available on our website cited above and in print at no cost:

- Audit and Corporate Performance Committee Charter
- Corporate Governance Committee Charter
- Organization and Compensation Committee Charter
- Corporate Governance Guidelines

h) Our 2012 Annual Meeting of Shareholders will be held on August 8, 2012, unless the Merger with Duke Energy has been completed by that date, in which case no 2012 Annual Meeting of Shareholders will be held. Shareholder proposals submitted for inclusion in the proxy statement for our 2012 Annual Meeting must be received no later than May 1, 2012, at our principal executive offices, addressed to the attention of:

John R. McArthur
Executive Vice President, General Counsel and Corporate Secretary
Progress Energy, Inc.
P.O. Box 1551
Raleigh, North Carolina 27602-1551

Upon receipt of any such proposal, we will determine whether or not to include such proposal in the proxy statement and proxy in accordance with regulations governing the solicitation of proxies.

A Progress Energy shareholder who otherwise intends to present business at the 2012 Annual Meeting of Shareholders, or who wishes to nominate a candidate for director, must comply with our By-Laws. Our By-Laws require, among other things, that for nominations of persons for election to the board of directors or the proposal of business not included in the notice of meeting to be considered by the shareholders at an annual meeting, a shareholder must give timely written notice thereof. To be timely for the 2012 Annual Meeting of Shareholders, our Corporate Secretary must receive that notice not later than May 1, 2012, and the Corporate Secretary must receive notice of a shareholder's intention to present other business not later than May 1, 2012. The notice must contain and be accompanied by certain information as specified in our By-Laws. We reserve the right to reject, rule out of order or take other appropriate action with respect to any proposal that does not comply with these or other applicable requirements.

Any shareholder desiring a copy of our By-Laws will be furnished one without charge upon written request to the Corporate Secretary. A copy of the By-Laws, as amended and restated on May 10, 2006, was filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, and is available at the SEC's website at www.sec.gov.

The information called for by Item 10 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 11. EXECUTIVE COMPENSATION

Information regarding Progress Energy's executive compensation and certain matters related to the Organization and Compensation Committee of Progress Energy's board is set forth in Progress Energy's definitive proxy statement for the 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is incorporated by reference herein. Information regarding PEC's executive compensation and PEC's decision to delegate authority to approve senior management compensation to the Organization and Compensation Committee of Progress Energy's board rather than having its own standing compensation committee is set forth in PEC's definitive proxy statement for the 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

The information called for by Item 11 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

a) Information regarding any person Progress Energy and PEC knows to be the beneficial owner of more than 5 percent of any class of its voting securities is set forth in its definitive proxy statement for the 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

b) Information regarding the security ownership of Progress Energy's and PEC's management is set forth, respectively, in Progress Energy's and PEC's definitive proxy statements for the 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

c) Information regarding the equity compensation plans of Progress Energy is set forth under the heading "Equity Compensation Plan Information" in Progress Energy's definitive proxy statement for the 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

The information called for by Item 12 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions is set forth, respectively, in Progress Energy's and PEC's definitive proxy statements for the 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

The information called for by Item 13 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The Audit Committee has actively monitored all services provided by its independent registered public accounting firm, Deloitte & Touche LLP, the member firms of Deloitte & Touche Tohmatsu, and their respective affiliates (collectively, Deloitte) and the relationship between audit and nonaudit services provided by Deloitte. Progress Energy has adopted policies and procedures for approving all audit and permissible nonaudit services rendered by Deloitte, and the fees billed for those services. These policies and procedures apply to Progress Energy and its subsidiaries. Progress Energy's Controller (the Controller) is responsible to the Audit Committee for enforcement of this procedure, and for reporting noncompliance. Pursuant to the preapproval policy, the Audit Committee specifically preapproved the use of Deloitte for audit, audit-related and tax services.

The preapproval policy requires management to obtain specific preapproval from the Audit Committee for the use of Deloitte for any permissible nonaudit services, which, generally, are limited to tax services, including tax compliance, tax planning, and tax advice services such as return review and consultation and assistance. Other types of permissible nonaudit services will not be considered for approval except in limited instances, which could include circumstances in which proposed services provide significant economic or other benefits to us. In determining whether to approve these services, the Audit Committee will assess whether these services adversely impair the independence of Deloitte. Any permissible nonaudit services provided during a fiscal year that (i) do not aggregate more than 5 percent of the total fees paid to Deloitte for all services rendered during that fiscal year and (ii) were not recognized as nonaudit services at the time of the engagement must be brought to the attention of the Controller for prompt submission to the Audit Committee for approval. These *de minimis* nonaudit services must be approved by the Audit Committee or its designated representative before the completion of the services. Nonaudit services that are specifically prohibited under Sarbanes-Oxley Act Section 404, SEC rules, and Public Company Accounting Oversight Board rules are specifically prohibited under the policy.

Prior to the approval of permissible tax services by the Audit Committee, the policy requires Deloitte to (1) describe in writing to the Audit Committee (a) the scope of the service, the fee structure for the engagement and any side letter or other amendment to the engagement letter or any other agreement between Progress Energy and Deloitte relating to the service and (b) any compensation arrangement or other agreement, such as a referral agreement, a referral fee or fee-sharing arrangement, between Deloitte and any person (other than Progress Energy) with respect to the promoting, marketing or recommending of a transaction covered by the service; and (2) discuss with the Audit Committee the potential effects of the services on the independence of Deloitte.

The policy also requires the Controller to update the Audit Committee throughout the year as to the services provided by Deloitte and the costs of those services. The policy also requires Deloitte to annually confirm its independence in accordance with SEC and New York Stock Exchange standards. The Audit Committee will assess the adequacy of this policy and related procedure as it deems necessary and revise accordingly.

Information regarding principal accountant fees and services is set forth, respectively, in Progress Energy's and PEC's definitive proxy statements for the 2012 Annual Meeting of Shareholders or will be filed with the SEC as part of an amendment to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

PEF

Set forth in the table below is certain information relating to the aggregate fees billed by Deloitte for professional services rendered to PEF for the fiscal years ended December 31.

	2011	2010
Audit fees	**$ 1,884,000**	$ 1,736,000
Audit-related fees	**8,000**	50,000
Tax fees	**4,000**	4,000
Total	**$ 1,896,000**	$ 1,790,000

Audit fees include fees billed for services rendered in connection with (i) the audits of the annual financial statements of PEF, (ii) the reviews of the financial statements included in the Quarterly Reports on Form 10-Q of PEF, (iii) accounting consultations arising as part of the audits and (iv) audit services in connection with statutory, regulatory or other filings, including comfort letters and consents in connection with SEC filings and financing transactions.

Audit-related fees include fees billed for (i) special procedures and letter reports, (ii) benefit plan audits when fees are paid by PEF rather than directly by the plan, (iii) accounting consultations for prospective transactions not arising directly from the audits, and (iv) accounting research tool subscriptions.

Tax fees include fees billed for tax compliance matters.

The Audit Committee has concluded that the provision of the nonaudit services listed above as Tax fees is compatible with maintaining Deloitte's independence.

None of the services provided was approved by the Audit Committee pursuant to the "de minimis" waiver provisions described above.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a) The following documents are filed as part of the report:

1. Financial Statements Filed:

   See Item 8 – Financial Statements and Supplementary Data

2. Financial Statement Schedules Filed:

   Consolidated Financial Statement Schedules for the Years Ended December 31, 2011, 2010 and 2009:

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

3. Exhibits Filed:

   See EXHIBIT INDEX

PROGRESS ENERGY, INC.
Schedule II - Valuation and Qualifying Accounts
For the Years Ended December 31
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expenses	Charged to Other Accounts	Deductions[a]	Balance at End of Period
Valuation and qualifying accounts deducted on the balance sheet from the related assets:					
2011					
Uncollectible accounts	**$ 35**	**$ 10**	**$ 1**	**$ (19)[b]**	**$ 27**
Inventory valuation[c]	**17**	**2**	**-**	**(2)**	**17**
Fossil fuel plants dismantlement reserve	**144**	**4**	**-**	**-**	**148**
Nuclear refueling outage reserve	**15**	**5**	**-**	**-**	**20**
Deferred tax asset valuation allowance	**60**	**11**	**-**	**-**	**71**
2010					
Uncollectible accounts	$ 18	$ 18	$ 24[b]	$ (25)	$ 35
Inventory valuation[c]	14	3	-	-	17
Fossil fuel plants dismantlement reserve	143	4	-	(3)	144
Nuclear refueling outage reserve	5	13	-	(3)	15
Deferred tax asset valuation allowance	55	5	-	-	60
2009					
Uncollectible accounts	$ 18	$ 32	$ -	$ (32)	$ 18
Inventory valuation[c]	-	14	-	-	14
Fossil fuel plants dismantlement reserve	145	1	-	(3)	143
Nuclear refueling outage reserve	14	18	-	(27)	5
Deferred tax asset valuation allowance	55	-	-	-	55

[a] Deductions from valuation accounts represent write-offs, net of recoveries, or the release of valuation allowances.
[b] Includes $6 million deduction in 2011 and $18 million charge in 2010 related to other noncustomer receivables.
[c] Relates to the impact of PEC's decision to retire 11 coal-fired units prior to the end of their estimated useful lives.

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
Schedule II - Valuation and Qualifying Accounts
For the Years Ended December 31
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expenses	Charged to Other Accounts	Deductions[a]	Balance at End of Period
Valuation and qualifying accounts deducted on the balance sheet from the related assets:					
2011					
Uncollectible accounts	**$ 10**	**$ 2**	**$ -**	**$ (3)**	**$ 9**
Inventory valuation[b]	**17**	**2**	**-**	**(2)**	**17**
2010					
Uncollectible accounts	$ 8	$ 3	$ 2	$ (3)	$ 10
Inventory valuation[b]	14	3	-	-	17
2009					
Uncollectible accounts	$ 6	$ 14	$ 1	$ (13)	$ 8
Inventory valuation[b]	-	14	-	-	14

[a] Deductions from valuation accounts represent write-offs, net of recoveries.
[b] Relates to the impact of PEC's decision to retire 11 coal-fired units prior to the end of their estimated useful lives.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.
Schedule II - Valuation and Qualifying Accounts
For the Years Ended December 31
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expenses	Charged to Other Accounts	Deductions[a]	Balance at End of Period
Valuation and qualifying accounts deducted on the balance sheet from the related assets:					
2011					
Uncollectible accounts	**$ 25**	**$ 8**	**$ 1**	**$ (16)**[b]	**$ 18**
Fossil fuel plants dismantlement reserve	**144**	**4**	**-**	**-**	**148**
Nuclear refueling outage reserve	**15**	**5**	**-**	**-**	**20**
2010					
Uncollectible accounts	$ 10	$ 15	$ 22[b]	$ (22)	$ 25
Fossil fuel plants dismantlement reserve	143	4	-	(3)	144
Nuclear refueling outage reserve	5	13	-	(3)	15
2009					
Uncollectible accounts	$ 11	$ 18	$ (1)	$ (18)	$ 10
Fossil fuel plants dismantlement reserve	145	1	-	(3)	143
Nuclear refueling outage reserve	14	18	-	(27)	5

[a] Deductions from valuation accounts represent write-offs, net of recoveries.
[b] Includes $6 million deduction in 2011 and $18 million charge in 2010 related to other noncustomer receivables.

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.

	PROGRESS ENERGY, INC.
Date: February 28, 2012	(Registrant)
	By: /s/ William D. Johnson William D. Johnson Chairman, President and Chief Executive Officer
	By: /s/ Mark F. Mulhern Mark F. Mulhern Senior Vice President and Chief Financial Officer
	By: /s/ Jeffrey M. Stone Jeffrey M. Stone Chief Accounting Officer and Controller

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/ William D. Johnson (William D. Johnson)	Chairman	February 28, 2012
/s/ John D. Baker II (John D. Baker II)	Director	February 28, 2012
/s/ James E. Bostic, Jr. (James E. Bostic, Jr.)	Director	February 28, 2012
/s/ Harris E. DeLoach, Jr. (Harris E. DeLoach, Jr.)	Director	February 28, 2012
/s/ James B. Hyler, Jr. (James B. Hyler, Jr.)	Director	February 28, 2012
/s/ Robert W. Jones (Robert W. Jones)	Director	February 28, 2012
/s/ W. Steven Jones (W. Steven Jones)	Director	February 28, 2012
/s/ Melquiades R. Martinez (Melquiades R. Martinez)	Director	February 28, 2012
/s/ E. Marie McKee (E. Marie McKee)	Director	February 28, 2012

/s/ John H. Mullin, III (John H. Mullin, III)	Director	February 28, 2012
/s/ Charles W. Pryor, Jr. (Charles W. Pryor, Jr.)	Director	February 28, 2012
/s/ Carlos A. Saladrigas (Carlos A. Saladrigas)	Director	February 28, 2012
/s/ Theresa M. Stone (Theresa M. Stone)	Director	February 28, 2012
/s/ Alfred C. Tollison, Jr. (Alfred C. Tollison, Jr.)	Director	February 28, 2012

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.

CAROLINA POWER & LIGHT COMPANY

Date: February 28, 2012

(Registrant)

By: /s/ Lloyd M. Yates
Lloyd M. Yates
President and Chief Executive Officer

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and Chief Financial Officer

By: /s/ Jeffrey M. Stone
Jeffrey M. Stone
Chief Accounting Officer

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/ William D. Johnson (William D. Johnson)	Chairman	February 28, 2012
/s/ Jeffrey A. Corbett (Jeffrey A. Corbett)	Director	February 28, 2012
/s/ Jeffrey J. Lyash (Jeffrey J. Lyash)	Director	February 28, 2012
/s/ John R. McArthur (John R. McArthur)	Director	February 28, 2012
/s/ Mark F. Mulhern (Mark F. Mulhern)	Director	February 28, 2012
/s/ James Scarola (James Scarola)	Director	February 28, 2012
/s/ Paula J. Sims (Paula J. Sims)	Director	February 28, 2012
/s/ Lloyd M. Yates (Lloyd M. Yates)	Director	February 28, 2012

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.

	FLORIDA POWER CORPORATION
Date: February 28, 2012	(Registrant)

By: /s/ Vincent M. Dolan
Vincent M. Dolan
President and Chief Executive Officer

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and Chief Financial Officer

By: /s/ Jeffrey M. Stone
Jeffrey M. Stone
Chief Accounting Officer

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/ William D. Johnson (William D. Johnson)	Chairman	February 28, 2012
/s/ Vincent M. Dolan (Vincent M. Dolan)	Director	February 28, 2012
/s/ Michael A. Lewis (Michael A. Lewis)	Director	February 28, 2012
/s/ Jeffrey J. Lyash (Jeffrey J. Lyash)	Director	February 28, 2012
/s/ John R. McArthur (John R. McArthur)	Director	February 28, 2012
/s/ Mark F. Mulhern (Mark F. Mulhern)	Director	February 28, 2012
/s/ Paula J. Sims (Paula J. Sims)	Director	February 28, 2012

EXHIBIT INDEX

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
*2a(1)	Agreement and Plan of Merger, dated as of January 8, 2011, by and among Duke Energy Corporation, Diamond Acquisition Corporation and Progress Energy, Inc. (filed as Exhibit 2.1 to the Current Report on Form 8-K, dated January 8, 2011, File No. 1-15929).	X		
*3a(1)	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(2)	Amended and Restated Articles of Incorporation of Progress Energy, Inc. (f/k/a 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		
*3a(3)	Articles of Amendment to the Amended and Restated Articles of Incorporation of Progress Energy, Inc. (f/k/a CP&L Energy, Inc.), dated December 4, 2000 (filed as Exhibit 3b(1) to Annual Report on Form 10-K for the year ended December 31, 2001, as filed with the SEC on March 28, 2002, File No. 1-15929).	X		
*3a(4)	Articles of Amendment to the Amended and Restated Articles of Incorporation of Progress Energy, Inc., dated May 10, 2006 (filed as Exhibit 3.A to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, File No. 1-15929, 1-3382 and 1-3274).	X		
*3a(5)	Amended Articles of Incorporation of Florida Power Corporation (filed as Exhibit 3(a) to the Progress Energy Florida Annual Report on Form 10-K for the year ended December 31, 1991, as filed with the SEC on March 30, 1992, File No. 1-3274).			X
*3b(1)	By-Laws of Progress Energy, Inc., as amended on May 10, 2006 (filed as Exhibit 3.B to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, File No. 1-15929, 1-3382 and 1-3274).	X		
*3b(2)	By-Laws of Carolina Power & Light Company, as amended on May 13, 2009 (filed as Exhibit 3.B to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, File No. 1-15929, 1-3382 and 1-3274).		X	
*3b(3)	By-Laws of Florida Power Corporation, as amended September 20, 2010 (filed as Exhibit 3.1 to the Florida Power Corporation Current Report on Form 8-K, dated September 20, 2010, File No. 1-3274).			X

*4a(1)	Description of Preferred Stock and the rights of the holders thereof (as set forth in Article Fourth of the Restated Charter of Carolina Power & Light Company, as amended, and Sections 1-9, 15, 16, 22-27, and 31 of the By-Laws of Carolina Power & Light Company, as amended (filed as Exhibit 4(f), File No. 33-25560).	X
*4a(2)	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(3)	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. 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;	X

	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); the Seventy-second Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated September 12, 2003, File No. 1-3382); the Seventy-third Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated March 22, 2005, File No. 1-3382); the Seventy-fourth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated November 30, 2005, File No. 1-3382); the Seventy-fifth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated March 13, 2008, File No. 1-3382); the Seventy-sixth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated January 8, 2009, File No. 1-3382); the Seventy-seventh Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated June 18, 2009, File No. 1-3382); and the Seventy-eighth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated September 12, 2011, File No. 1-3382).	
*4b(2)	Indenture, dated as of January 1, 1944 (the "Indenture"), between Florida Power Corporation and Guaranty Trust Company of New York and The Florida National Bank of Jacksonville, as Trustees (filed as Exhibit B-18 to Florida Power's Registration Statement on Form A-2) (No. 2-5293) filed with the SEC on January 24, 1944).	X
*4b(3)	Seventh Supplemental Indenture (filed as Exhibit 4(b) to Florida Power Corporation's Registration Statement on Form S-3 (No. 33-16788) filed with the SEC on September 27, 1991); and the Eighth Supplemental Indenture (filed as Exhibit 4(c) to Florida Power Corporation's Registration Statement on Form S-3 (No. 33-16788) filed with the SEC on September 27, 1991); and the Sixteenth Supplemental Indenture (filed as Exhibit 4(d) to Florida Power Corporation's Registration Statement on Form S-3 (No. 33-16788) filed with the SEC on September 27, 1991); and the Twenty-ninth Supplemental Indenture (filed as Exhibit 4(c) to Florida Power Corporation's Registration Statement on Form S-3 (No. 2-79832) filed with the SEC on September 17, 1982); and the Thirty-eighth Supplemental Indenture (filed as exhibit 4(f) to Florida Power's Registration Statement on Form S-3 (No. 33-55273) as filed with the SEC on August 29, 1994); and the Thirty-ninth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on July 23, 2001); and the Fortieth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on February 18, 2003); and the Forty-first Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on February 21, 2003);	X

	and the Forty-second Supplemental Indenture (filed as Exhibit 4 to Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 filed with the SEC on September 11, 2003); and the Forty-third Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on November 21, 2003); and the Forty-fourth Supplemental Indenture (filed as Exhibit 4.(m) to the Progress Energy Florida Annual Report on Form 10-K dated March 16, 2005); and the Forty-fifth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K, filed on May 16, 2005); and the Forty-sixth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on September 19, 2007); the Forty-seventh Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on December 13, 2007); the Forty-eighth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on June 18, 2008); the Forty-ninth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on March 25, 2010); and the Fiftieth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on August 18, 2011).			
*4b(4)	Indenture, dated as of December 7, 2005, between Florida Power Corporation and J.P. Morgan Trust Company, National Association, as Trustee with respect to Senior Notes, (filed as Exhibit 4(a) to Current Report on Form 8-K dated December 13, 2005, File No. 1-3274).			X
*4b(5)	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	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	
*4d	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), (Exhibit 4(b) to Current Report on Form 8-K dated November 5, 1999, File No. 1-3382).		X	

*4e	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	
*10b(1)	Progress Energy, Inc. Amended and Restated Credit Agreement dated as of February 15, 2012 (filed as Exhibit 10.1 to Current Report on Form 8-K dated February 15, 2012, File No. 1-15929).	X		
*10b(2)	Carolina Power & Light Company 3-Year $750,000,000 Credit Agreement, dated as of October 15, 2010 (filed as Exhibit 10.1 to Current Report on Form 8-K dated October 15, 2010, File No. 1-15929, 1-3382 and 1-3274).		X	
*10b(3)	Florida Power Corporation 3-Year $750,000,000 Credit Agreement, dated as of October 15, 2010 (filed as Exhibit 10.2 to Current Report on Form 8-K dated October 15, 2010, File No. 1-15929, 1-3382 and 1-3274).			X

-+*10c(1)	Retirement Plan for Outside Directors (filed as Exhibit 10(i), File No. 33-25560).		X	
+*10c(2)	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(3)	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	X
+*10c(4)	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	X
+*10c(5)	2002 Progress Energy, Inc. Equity Incentive Plan, Amended and Restated effective January 1, 2007 (filed as Exhibit 10c(5) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*10c(6)	Amended and Restated Broad-Based Performance Share Sub-Plan, Exhibit B to the 2002 Progress Energy, Inc. Equity Incentive Plan, effective January 1, 2007 (filed as Exhibit 10c(6) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*10c(7)	Amended and Restated Executive and Key Manager Performance Share Sub-Plan, Exhibit A to the 2002 Progress Energy, Inc. Equity Incentive Plan (effective January 1, 2007) (filed as Exhibit 10c(7) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*10c(8)	Progress Energy, Inc. 2007 Equity Incentive Plan (filed as Exhibit C to Form DEF 14A, as filed with the SEC on March 30, 2007, File No. 1-15929).	X	X	X
+*10c(9)	Executive and Key Manager 2007 Performance Share Sub-Plan, Exhibit A to the 2007 Equity Incentive Plan, effective January 1, 2007 (filed as Exhibit 10.1 to Current Report on Form 8-K dated July 16, 2007, File No. 1- 15929, No. 1-3382 and No. 1-3274).	X	X	X
+*10c(10)	Form of Progress Energy, Inc. Restricted Stock Agreement pursuant to the 2002 Progress Energy Inc. Equity Incentive Plan, as amended July 2002 (filed as Exhibit 10c(18) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X	X	X

+*10c(11)	Form of Employment Agreement dated May 8, 2007 between (i) Progress Energy Service Company, LLC and Robert McGehee, John R. McArthur and Peter M. Scott III; (ii) PEC and Lloyd M. Yates, Fredrick N. Day IV, Paula M. Sims, William D. Johnson and Clayton S. Hinnant; and (iii) PEF and Jeffrey A. Corbett and Jeffrey J. Lyash (filed as Exhibit 10 to Quarterly Report on Form 10-Q for the period ended March 31, 2007, File No. 1-15929, No. 1-3382 and No. 1-3274).	X	X	X
+*10c(12)	Form of Employment Agreement between Progress Energy Service Company, LLC and Mark F. Mulhern dated September 18, 2007 (filed as Exhibit 10 to Quarterly Report on Form 10-Q for the period ended March 31, 2007, File No. 1-15929, No. 1-3382 and No. 1-3274).	X		
+*10c(13)	Amendment, dated August 5, 2005, to Employment Agreement dated between Progress Energy Service Company, LLC and Peter M. Scott III (filed as Exhibit 10 to Quarterly Report on Form 10-Q for the period ended June 30, 2005, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(14)	Selected Executives Supplemental Deferred Compensation Program Agreement, dated August, 1996, between CP&L and C. S. Hinnant (filed as Exhibit 10c(22) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).		X	
+*10c(15)	Form of Executive Permanent Life Insurance Agreement (filed as Exhibit 10c(23) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X		
+*10c(16)	Form of Executive and Key Manager 2008 Performance Share Sub-Plan (filed as Exhibit 10(a) to Quarterly Report on Form 10-Q for the period ended March 31, 2008, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(17)	Progress Energy, Inc. 2009 Executive Incentive Plan, effective March 17, 2009 (filed as Exhibit D to Form DEF 14A, as filed with the SEC on March 31, 2009, File No. 1-15929).	X		
+*10c(18)	Employment Agreement Term Sheet for William D. Johnson in connection with the Agreement and Plan of Merger, dated as of January 8, 2011, by and among Duke Energy Corporation, Diamond Acquisition Corporation and Progress Energy, Inc. (Exhibit C to the Agreement and Plan of Merger filed as Exhibit 2.1 to the Current Report on Form 8-K, dated January 8, 2011, File No. 1-15929).	X		

+*10c(19)	Form of Letter Agreement, dated January 8, 2011, executed by certain officers of Progress Energy, Inc., waiving certain rights under Progress Energy, Inc.'s Management Change-in-Control Plan and their employment agreements (filed as Exhibit 10.1 to the Current Report on Form 8-K dated January 8, 2011, File No. 1-15929).	X		
+*10c(20)	Deferred Compensation Plan for Key Management Employees of Progress Energy, Inc., amended and restated effective July 13, 2011 (filed as Exhibit 10(a) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(21)	Executive and Key Manager 2009 Performance Share Sub-Plan, Exhibit A to 2007 Equity Incentive Plan, amended and restated effective July 12, 2011 (filed as Exhibit 10(b) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274.	X	X	X
+*10c(22)	Amended Management Incentive Compensation Plan of Progress Energy, Inc., amended and restated effective July 12, 2011 (filed as Exhibit 10(c) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(23)	Progress Energy, Inc. Management Change-in-Control Plan, amended and restated effective July 13, 2011 (filed as Exhibit 10(d) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(24)	Progress Energy, Inc. Amended and Restated Management Deferred Compensation Plan, revised and restated effective July 12, 2011 (filed as Exhibit 10(e) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(25)	Progress Energy, Inc. Non-Employee Director Deferred Compensation Plan, amended and restated effective July 13, 2011 (filed as Exhibit 10(f) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(26)	Progress Energy, Inc. Non-Employee Director Stock Unit Plan, amended and restated effective July 13, 2011 (filed as Exhibit 10(g) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(27)	Amended and Restated Progress Energy, Inc. Restoration Retirement Plan, amended and restated effective July 13, 2011 (filed as Exhibit 10(h) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X

+*10c(28)	Amended and Restated Supplemental Senior Executive Retirement Plan of Progress Energy, Inc., amended and restated effective July 13, 2011 (filed as Exhibit 10(i) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+10c(29)	Form of Progress Energy, Inc. Restricted Stock Unit Award Agreement (Graded Vesting), effective September 15, 2011.	X	X	X
+10c(30)	Form of Progress Energy, Inc. Restricted Stock Unit Award Agreement (Cliff Vesting), effective September 15, 2011.	X	X	X
+10c(31)	First Amendment to the Progress Energy, Inc. Amended and Restated Management Deferred Compensation Plan, effective December 14, 2011.	X	X	X
+10c(32)	First Amendment to the Progress Energy, Inc. Amended Management Incentive Compensation Plan, effective December 14, 2011.	X	X	X
*10d(1)	Precedent and Related Agreements among Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), Southern Natural Gas Company, Florida Gas Transmission Company ("FGT"), and BG LNG Services, LLC ("BG"), including: a) Precedent Agreement by and between Southern Natural Gas Company 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, (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.)	X		X

*10d(2)	Engineering, Procurement and Construction Agreement, dated as of December 31, 2008, between Florida Power Corporation d/b/a/ Progress Energy Florida, Inc., as owner, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for a two-unit AP1000 Nuclear Power Plant (filed as Exhibit 10.1 to Current Report on Form 8-K filed on March 2, 2009). (The Registrants have requested confidential treatment for certain portions of this exhibit pursuant to an application for confidential treatment submitted to the SEC. These portions have been omitted from the above-referenced Current Report and submitted separately to the SEC.)	X		X
12(a)	Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Dividends Combined.	X		
12(b)	Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Dividends Combined.		X	
12(c)	Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Dividends Combined.			X
21	Subsidiaries of Progress Energy, Inc.	X		
23	Consent of Deloitte & Touche LLP.	X		
31(a)	302 Certification of Chief Executive Officer	X		
31(b)	302 Certification of Chief Financial Officer	X		
31(c)	302 Certification of Chief Executive Officer		X	
31(d)	302 Certification of Chief Financial Officer		X	
31(e)	302 Certification of Chief Executive Officer			X
31(f)	302 Certification of Chief Financial Officer			X
32(a)	906 Certification of Chief Executive Officer	X		
32(b)	906 Certification of Chief Financial Officer	X		
32(c)	906 Certification of Chief Executive Officer		X	
32(d)	906 Certification of Chief Financial Officer		X	
32(e)	906 Certification of Chief Executive Officer			X
32(f)	906 Certification of Chief Financial Officer			X

101.INS	XBRL Instance Document**	X	X	X
101.SCH	XBRL Taxonomy Extension Schema Document	X	X	X
101.CAL	XBRL Taxonomy Calculation Linkbase Document	X	X	X
101.LAB	XBRL Taxonomy Label Linkbase Document	X	X	X
101.PRE	XBRL Taxonomy Presentation Linkbase Document	X	X	X
101.DEF	XBRL Taxonomy Definition Linkbase Document	X	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 15 (b) 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.
**Attached as Exhibit 101 are the following financial statements and notes thereto for Progress Energy, PEC and PEF from the Annual Report on Form 10-K for the year ended December 31, 2011, formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Income, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Changes in Total Equity, (v) the Consolidated Statements of Comprehensive Income and (vi) the Notes to the Consolidated Financial Statements, which are tagged as blocks of text in respect to PEC and PEF's disclosures.

In accordance with Rule 406T of Regulation S-T, the XBRL-related information for PEC and PEF in Exhibit 101 to this Annual Report on Form 10-K is deemed not filed or part of a registration statement or prospectus for purposes of Section 11 or 12 of the Securities Act, is deemed not filed for purposes of Section 18 of the Exchange Act and otherwise is not subject to liability under these sections.

Exhibit No. 10c(29)

PROGRESS ENERGY, INC.

RESTRICTED STOCK UNIT AWARD AGREEMENT

Non-transferable

GRANT TO

Name of the Employee
("Grantee")

by Progress Energy, Inc. (the "Sponsor") of *X,XXX*

Restricted Stock Units (the "Units") representing the right to earn, on a one-for-one basis, shares of the Sponsor's common stock ("Stock"), pursuant to and subject to the provisions of the Progress Energy, Inc. Amended and Restated 2007 Equity Incentive Plan (the "Plan") and to the terms and conditions set forth on the following pages of this award agreement ("Agreement"). Capitalized terms used herein and not otherwise defined shall have the meanings assigned to such terms in the Plan.

By accepting this award, Grantee shall be deemed to have agreed to the terms and conditions of this Agreement and the Plan. Unless vesting is accelerated as provided in section 2 of the Terms and Conditions or otherwise in the discretion of the Sponsor's Committee on Organization and Compensation ("Committee"), the Units shall vest (become non-forfeitable) in one-third increments on each of the first, second and third anniversaries of the Grant Date.

IN WITNESS WHEREOF, Progress Energy, Inc. has caused this Agreement to be executed as of the Grant Date, as indicated below.

PROGRESS ENERGY, INC.

/S/ William D. Johnson
By: William D. Johnson
Chairman, President, and Chief Executive Officer

Grant Date: ______________________________

Acceptance Date: __________________________

TERMS AND CONDITIONS

1. Grant of Units. Each Unit represents the right to receive one share of the Sponsor's Stock on the terms set forth in this Agreement.

2. Vesting of Units. The Units have been credited to a bookkeeping account on behalf of Grantee. The Units will vest and become non-forfeitable on the earliest to occur of the following (the "Vesting Date"):

(a) As to one-third of the units on the first anniversary of the Grant Date, another one-third on the second anniversary of the Grant Date, and the remaining one-third on the third anniversary of the Grant Date;

(b) As to all of the Units, the termination of Grantee's employment with the Company due to death or Disability (as defined for purposes of Code Section 409A) at least one year following the Grant Date;

(c) As to all of the Units, the involuntary termination of Grantee's employment with the Company due to Divestiture;

(d) As to all of the Units, upon the occurrence of a Change in Control (as defined for purposes of Code Section 409A), if the Units are not assumed by the surviving company or equitably converted or substituted;

(e) As to all of the Units, upon termination of Grantee's employment by Sponsor without Cause at any time after a Change in Control; or

(f) As to all of the Units, upon Grantee's Normal Retirement on or after attaining age 65. Upon Grantee's Early Retirement on or after age 55 with 10 or more years of service, a prorata percentage of the then-unvested Units, if any, will vest based upon the number of full months elapsed between the Grant Date and the date of Early Retirement, divided by the number of months within the applicable vesting period described in 2(a) above; or

(g) Upon Grantee's termination of employment under the terms of the Voluntary Separation Plan ("VSP") established by the Company in connection with, and in anticipation of, the transactions described in the Agreement and Plan of Merger between the Company and Duke Energy Corporation dated as of January 8, 2011 if the Grantee is eligible to participate in the VSP and satisfies the requirements to receive benefits under the VSP, a prorata percentage of the then-unvested Units, if any, will vest based upon the number of full months elapsed between the Grant Date and the date of termination of employment, divided by the number of months within the applicable vesting period described in 2(a) above.

If Grantee's employment terminates prior to the Vesting Date for any reason other than as described in (b), (c) or (e) or (f) above, Grantee shall forfeit all right, title and interest in and to the then unvested Units as of the date of such termination and the unvested Units will be reconveyed to the Sponsor without further consideration or any act or action by Grantee.

3. Conversion to Stock. Unless the Units are forfeited prior to the Vesting Date as provided in Section 2 above, the Units will be converted to Shares on the later of (i) the Vesting Date, or (ii) if required to comply with Code Section 409A and Treasury regulations and guidance with respect to such law, the six-month anniversary of Grantee's separation from service (the "Conversion Date"). Such Shares will be registered on the books of the Sponsor in Grantee's name as of the Conversion Date and delivered to Grantee within 30 days thereafter, in certificated or uncertificated form, as the Participant shall direct.

4. Dividend Equivalents. If and when cash dividends or other cash distributions are paid with respect to the Stock while the Units are outstanding, the dollar amount of such dividends or distributions with respect to the number of Shares then underlying the Units will be paid to Grantee within 30 days after the date that dividends are paid to shareholders of the Sponsor.

5. Rights as Stockholder. Except for the right to receive Dividend Equivalents as provided in Section 4 above, Grantee shall not have any rights as a stockholder of the Sponsor with respect to the Units, including voting rights, until conversion of the Units to shares of Stock. Upon conversion of the Units into shares of Stock, Grantee will obtain full voting and other rights as a stockholder of the Sponsor.

6. Restrictions on Transfer. The Units may not be sold, transferred, exchanged, assigned, pledged, hypothecated or otherwise encumbered to or in favor of any party other than the Company, or be subjected to any lien, obligation or liability of Grantee to any other party other than the Company.

7. No Right of Continued Employment. Nothing in this Agreement shall interfere with or limit in any way the right of the Company to terminate Grantee's employment at any time, nor confer upon Grantee any right to continue in the employ of the Company.

8. Payment of Taxes. The Company has the authority and the right to deduct or withhold, or require Grantee to remit to the employer, an amount sufficient to satisfy federal, state, and local taxes (including Grantee's FICA obligation) required by law to be withheld with respect to any taxable event arising as a result of the vesting or settlement of the Units. The obligations of the Sponsor under this Agreement will be conditional on such payment or arrangements, and the Sponsor, and, where applicable, its Affiliates will, to the extent permitted by law, have the right to deduct any such taxes from any payment of any kind otherwise due to Grantee. Grantee hereby authorizes the Company to instruct a third party broker or plan administrator to sell Shares earned by Grantee upon settlement of the Units in an amount sufficient to satisfy the amount required to be withheld for tax purposes, and to remit the cash proceeds from such sale to the Company.

9. Amendment. The Committee may amend, modify or terminate this Agreement without approval of Grantee; provided, however, that such amendment, modification or termination shall not, without Grantee's consent, reduce or diminish the value of this award determined as if it had been fully vested (i.e., as if all restrictions on the Units hereunder had expired) on the date of such amendment or termination.

10. Plan Controls. The terms contained in the Plan are incorporated into and made a part of this Agreement and this Agreement shall be governed by and construed in accordance with the Plan. In the event of any actual or alleged conflict between the provisions of the Plan and the provisions of this Agreement, the provisions of the Plan shall be controlling and determinative.

11. Successors. This Agreement shall be binding upon any successor of the Sponsor, in accordance with the terms of this Agreement and the Plan.

12. Severability. If any one or more of the provisions contained in this Agreement is invalid, illegal or unenforceable, the other provisions of this Agreement will be construed and enforced as if the invalid, illegal or unenforceable provision had never been included.

13. Notice. Notices and communications under this Agreement must be in writing and either personally delivered or sent by registered or certified United States mail, return receipt requested, postage prepaid. Notices to the Sponsor must be addressed to:

Progress Energy, Inc.
410 South Wilmington Street
Raleigh, NC 27601
Attn: General Counsel

or any other address designated by the Sponsor in a written notice to Grantee. Notices to Grantee will be directed to the address of Grantee then currently on file with the Sponsor, or at any other address given by Grantee in a written notice to the Sponsor.

Exhibit No. 10c(30)

<u>PROGRESS ENERGY, INC.</u>

RESTRICTED STOCK UNIT AWARD AGREEMENT

Non-transferable

GRANT TO

Name of the Employee
("Grantee")

by Progress Energy, Inc. (the "Sponsor") of *X,XXX*

Restricted Stock Units (the "Units") representing the right to earn, on a one-for-one basis, shares of the Sponsor's common stock ("Stock"), pursuant to and subject to the provisions of the Progress Energy, Inc. Amended and Restated 2007 Equity Incentive Plan (the "Plan") and to the terms and conditions set forth on the following pages of this award agreement ("Agreement"). Capitalized terms used herein and not otherwise defined shall have the meanings assigned to such terms in the Plan.

By accepting this award, Grantee shall be deemed to have agreed to the terms and conditions of this Agreement and the Plan. Unless vesting is accelerated as provided in section 2 of the Terms and Conditions or otherwise in the discretion of the Sponsor's Committee on Organization and Compensation ("Committee"), the Units shall vest (become non-forfeitable) on the ***third*** anniversary of the Grant Date.

IN WITNESS WHEREOF, Progress Energy, Inc. has caused this Agreement to be executed as of the Grant Date, as indicated below.

PROGRESS ENERGY, INC.

/S/ William D. Johnson
By: William D. Johnson
Chairman, President, and Chief Executive Officer

Grant Date: ______________________________

Acceptance Date: __________________________

TERMS AND CONDITIONS

1. Grant of Units. Each Unit represents the right to receive one share of the Sponsor's Stock on the terms set forth in this Agreement.

2. Vesting of Units. The Units have been credited to a bookkeeping account on behalf of Grantee. The Units will vest and become non-forfeitable on the earliest to occur of the following (the "Vesting Date"):

(a) As to all of the units, on the third anniversary of the Grant Date;

(b) As to all of the Units, the termination of Grantee's employment with the Company due to death or Disability (as defined for purposes of Code Section 409A) at least one year following the Grant Date;

(c) As to all of the Units, the involuntary termination of Grantee's employment with the Company due to Divestiture;

(d) As to all of the Units, upon the occurrence of a Change in Control (as defined for purposes of Code Section 409A), if the Units are not assumed by the surviving company or equitably converted or substituted;

(e) As to all of the Units, upon termination of Grantee's employment by Sponsor without Cause at any time after a Change in Control; or

(f) As to all of the Units, upon Grantee's Normal Retirement on or after attaining age 65. Upon Grantee's Early Retirement on or after age 55 with 10 or more years of service, a prorata percentage of the then-unvested Units, if any, will vest based upon the number of full months elapsed between the Grant Date and the date of Early Retirement, divided by 36; or

(g) Upon Grantee's termination of employment under the terms of the Voluntary Separation Plan ("VSP") established by the Company in connection with, and in anticipation of, the transactions described in the Agreement and Plan of Merger between the Company and Duke Energy Corporation dated as of January 8, 2011 if the Grantee is eligible to participate in the VSP and satisfies the requirements to receive benefits under the VSP, a prorata percentage of the then-unvested Units, if any, will vest based upon the number of full months elapsed between the Grant Date and the date of termination of employment, divided by the number of months within the applicable vesting period described in 2(a) above.

If Grantee's employment terminates prior to the Vesting Date for any reason other than as described in (b), (c) or (e) or (f) above, Grantee shall forfeit all right, title and interest in and to the then unvested Units as of the date of such termination and the unvested Units will be reconveyed to the Sponsor without further consideration or any act or action by Grantee.

3. Conversion to Stock. Unless the Units are forfeited prior to the Vesting Date as provided in Section 2 above, the Units will be converted to Shares on the later of (i) the Vesting Date, or (ii) if required to comply with Code Section 409A and Treasury regulations and guidance with respect to such law, the six-month anniversary of Grantee's separation from service (the "Conversion Date"). Such Shares will be registered on the books of the Sponsor in Grantee's name as of the Conversion Date and delivered to Grantee within 30 days thereafter, in certificated or uncertificated form, as the Participant shall direct.

4. Dividend Equivalents. If and when cash dividends or other cash distributions are paid with respect to the Stock while the Units are outstanding, the dollar amount of such dividends or distributions with respect to the number of Shares then underlying the Units will be paid to Grantee within 30 days after the date that dividends are paid to shareholders of the Sponsor.

5. Rights as Stockholder. Except for the right to receive Dividend Equivalents as provided in Section 4 above, Grantee shall not have any rights as a stockholder of the Sponsor with respect to the Units, including voting rights, until conversion of the Units to shares of Stock. Upon conversion of the Units into shares of Stock, Grantee will obtain full voting and other rights as a stockholder of the Sponsor.

6. Restrictions on Transfer. The Units may not be sold, transferred, exchanged, assigned, pledged, hypothecated or otherwise encumbered to or in favor of any party other than the Company, or be subjected to any lien, obligation or liability of Grantee to any other party other than the Company.

7. No Right of Continued Employment. Nothing in this Agreement shall interfere with or limit in any way the right of the Company to terminate Grantee's employment at any time, nor confer upon Grantee any right to continue in the employ of the Company.

8. Payment of Taxes. The Company has the authority and the right to deduct or withhold, or require Grantee to remit to the employer, an amount sufficient to satisfy federal, state, and local taxes (including Grantee's FICA obligation) required by law to be withheld with respect to any taxable event arising as a result of the vesting or settlement of the Units. The obligations of the Sponsor under this Agreement will be conditional on such payment or arrangements, and the Sponsor, and, where applicable, its Affiliates will, to the extent permitted by law, have the right to deduct any such taxes from any payment of any kind otherwise due to Grantee. Grantee hereby authorizes the Company to instruct a third party broker or plan administrator to sell Shares earned by Grantee upon settlement of the Units in an amount sufficient to satisfy the amount required to be withheld for tax purposes, and to remit the cash proceeds from such sale to the Company.

9. Amendment. The Committee may amend, modify or terminate this Agreement without approval of Grantee; provided, however, that such amendment, modification or termination shall not, without Grantee's consent, reduce or diminish the value of this award determined as if it had been fully vested (i.e., as if all restrictions on the Units hereunder had expired) on the date of such amendment or termination.

10. Plan Controls. The terms contained in the Plan are incorporated into and made a part of this Agreement and this Agreement shall be governed by and construed in accordance with the Plan. In the event of any actual or alleged conflict between the provisions of the Plan and the provisions of this Agreement, the provisions of the Plan shall be controlling and determinative.

11. Successors. This Agreement shall be binding upon any successor of the Sponsor, in accordance with the terms of this Agreement and the Plan.

12. Severability. If any one or more of the provisions contained in this Agreement is invalid, illegal or unenforceable, the other provisions of this Agreement will be construed and enforced as if the invalid, illegal or unenforceable provision had never been included.

13. Notice. Notices and communications under this Agreement must be in writing and either personally delivered or sent by registered or certified United States mail, return receipt requested, postage prepaid. Notices to the Sponsor must be addressed to:

Progress Energy, Inc.
410 South Wilmington Street
Raleigh, NC 27601
Attn: General Counsel

or any other address designated by the Sponsor in a written notice to Grantee. Notices to Grantee will be directed to the address of Grantee then currently on file with the Sponsor, or at any other address given by Grantee in a written notice to the Sponsor.

Exhibit No. 10c(31)

FIRST AMENDMENT TO THE
MANAGEMENT DEFERRED COMPENSATION PLAN
AS AMENDED AND RESTATED

WHEREAS, Progress Energy, Inc. (the "Company") sponsors and maintains the Management Deferred Compensation Plan as amended and restated effective July 12, 2011 (the "MDCP");

WHEREAS, the Company desires to amend the MDCP to provide that participants be permitted to make investment elections on a daily basis;

NOW, THEREFORE, BE IT RESOLVED, that the MDCP is hereby amended effective as of December 14, 2011 as follows:

1. Section 4.6(a) is amended to read as follows:

   (a) A Participant may elect to reallocate the value of his Phantom Investment Subaccounts comprising his Deferral Account among other Phantom Investment Subaccounts and change the allocation of future Deferrals among Phantom Investment Subaccounts on a daily basis (or on such other basis as the Committee shall approve) pursuant to uniform rules and procedures adopted by the Committee. Provided, however, that Participants may not reallocate the value of his Phantom Investment Subaccounts into Phantom Stock Units.

IN WITNESS WHEREOF, this instrument has been executed this 20th day of December, 2011.

PROGRESS ENERGY, INC.

By: ___________________________________

Exhibit No. 10c(32)

FIRST AMENDMENT TO THE AMENDED MANAGEMENT INCENTIVE COMPENSATION PLAN

WHEREAS, Progress Energy, Inc. (the “Company”) sponsors and maintains the Management Incentive Compensation Plan as amended July 12, 2011 (the “MICP”);

WHEREAS, the Company entered into the Agreement and Plan of Merger with Duke Energy Corporation (“Duke”) dated as of January 8, 2011 (the “Merger Agreement”);

WHEREAS, the Merger Agreement provides that the Company and Duke shall cooperate to establish common severance policies or plans; and

WHEREAS, the Company has adopted a voluntary separation plan to assist in the integration of the operations of the Company and Duke and to allow the combined entities to achieve appropriate staffing levels and to provide benefits to employees of the Company and its affiliates who terminate employment in connection with, or in anticipation of, the combination of the Company and Duke (the “VSP”); and

WHEREAS, the Company desires to amend the MICP to provide that participants in the VSP will receive an award that is not less than the prorated benefit payable based upon achievement of the Performance Measures as adjusted in accordance with the terms of the MICP; and

WHEREAS, in anticipation of the completion of the transactions contemplated by the Merger Agreement, the Company further desires to amend the MICP to provide that participants in the MICP not be permitted to defer any portion the Plan Award that he or she may earn for the 2012 Year;

NOW, THEREFORE, BE IT RESOLVED, that the MICP is hereby amended effective as of December 14, 2011 as follows:

1. Article VII of the MICP is amended by restating it in its entirety as follows:

   Except as otherwise provided in this Article VII, a Participant must be actively employed by the Company on the next January 1 immediately following the Year for which a Plan Award is earned in order to be eligible for payment of an Award for that Year. In the event the active employment of a participant shall terminate or be terminated for any reason, including death, before the next January 1 immediately following the Year for which a Plan Award is earned, such Participant shall receive his or her Award for the year, if any, in an amount that the Chief Executive Officer of the Sponsor deems appropriate. Notwithstanding the foregoing provisions of this Article VII, in the event the employment of a Participant is terminated by the Company without Cause within one (1) year following a Change in Control, the Award of the Participant for the Year in which the termination occurs shall equal the amount of the Award which would have been earned for the Year if the Participant had remained in the employment of the Company through December 31, pro rated to reflect the portion of the Year completed by the Participant as an employee.

2. Section 2 of Article VI is amended by inserting the following sentence at the end thereof:

   This Section 2 shall not apply to Plan Awards earned for the Year 2012.

3. Section 5 of Article VI is amended by replacing in its entirety the second sentence thereof with the following sentence:

> The Participant may elect to reallocate the value of his Phantom Investment Subaccounts among other Phantom Investment Subaccounts on a daily basis (or on such other basis as the Committee shall approve), pursuant to uniform rules and procedures adopted by the Compensation Committee.

IN WITNESS WHEREOF, this instrument has been executed this 20th day of December, 2011.

PROGRESS ENERGY, INC.

By: ____________________________________

Exhibit No. 12(a)

PROGRESS ENERGY, INC.
Computation of Ratio of Earnings to Fixed Charges and
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined
For the Years Ended December 31

(dollars in millions)	**2011**	2010[a]	2009[a]	2008[a]	2007[a]
EARNINGS, AS DEFINED:					
Add:					
Pre-tax income from continuing operations	**$ 910**	$ 1,406	$ 1,237	$ 1,173	$ 1,036
Fixed charges, as below	**827**	846	813	768	677
Deduct:					
Capitalized interest[b]	**35**	32	39	40	17
Pre-tax income (loss) attributable to noncontrolling interests of subsidiaries that have not incurred fixed charges	**3**	3	-	5	9
Preference security dividend requirements of consolidated subsidiaries	**6**	7	7	7	7
Total earnings, as defined	**$ 1,693**	$ 2,210	$ 2,004	$ 1,889	$ 1,680
FIXED CHARGES, AS DEFINED:					
Interest on debt, including capitalized portion	**$ 769**	$ 788	$ 774	$ 679	$ 618
Estimate of interest within rental expense	**52**	51	32	82	52
Preference security dividend requirements of consolidated subsidiaries	**6**	7	7	7	7
Total fixed charges, as defined	**$ 827**	$ 846	$ 813	$ 768	$ 677
Ratio of Earnings to Fixed Charges	**2.05**	2.61	2.46	2.46	2.48
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined[c]	**2.05**	2.61	2.46	2.46	2.48

[a] Prior periods have been revised primarily to include (1) interest within discontinued operations and (2) purchased power agreements classified as leases in the estimate of interest within rental expense.

[b] Excludes equity costs related to allowance for equity funds used during construction that are included in other income (expense) on the Consolidated Statements of Income.

[c] For all periods presented, we had no preferred stock outstanding.

Exhibit No. 12(b)

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
Computation of Ratio of Earnings to Fixed Charges and
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined
For the Years Ended December 31

(dollars in millions)	**2011**	2010[a]	2009[a]	2008[a]	2007[a]
EARNINGS, AS DEFINED:					
Add:					
Pre-tax income	**$ 772**	$ 952	$ 791	$ 832	$ 796
Fixed charges, as below	**235**	227	219	231	226
Deduct:					
Capitalized interest[b]	**21**	19	12	12	5
Pre-tax loss attributable to noncontrolling interests of subsidiaries that have not incurred fixed charges	**-**	(1)	(2)	-	-
Total earnings, as defined	**$ 986**	$ 1,161	$ 1,000	$ 1,051	$ 1,017
FIXED CHARGES, AS DEFINED:					
Interest on debt, including capitalized portion	**$ 205**	$ 205	$ 207	$ 219	$ 215
Estimate of interest within rental expense	**30**	22	12	12	11
Total fixed charges, as defined	**235**	227	219	231	226
Preferred dividends, as defined	**4**	5	5	5	5
Total fixed charges and preferred dividends combined	**$ 239**	$ 232	$ 224	$ 236	$ 231
Ratio of Earnings to Fixed Charges	**4.20**	5.11	4.57	4.55	4.50
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**4.13**	5.00	4.46	4.45	4.40

[a] Prior periods have been revised primarily to include purchased power agreements classified as leases in the estimate of interest within rental expense.

[b] Excludes equity costs related to allowance for equity funds used during construction that are included in other income (expense) on the Consolidated Statements of Income.

Exhibit No. 12(c)

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.
Computation of Ratio of Earnings to Fixed Charges and
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined
For the Years Ended December 31

(dollars in millions)	**2011**	2010[a]	2009[a]	2008[a]	2007[a]
EARNINGS, AS DEFINED:					
Add:					
Pre-tax income	**$ 494**	$ 729	$ 671	$ 566	$ 461
Fixed charges, as below	**275**	300	278	305	224
Deduct:					
Capitalized interest[b]	**14**	13	27	28	12
Total earnings, as defined	**$ 755**	$ 1,016	$ 922	$ 843	$ 673
FIXED CHARGES, AS DEFINED:					
Interest on debt, including capitalized portion	**$ 253**	$ 271	$ 258	$ 236	$ 185
Estimate of interest within rental expense	**22**	29	20	69	39
Total fixed charges, as defined	**275**	300	278	305	224
Preferred dividends, as defined	**2**	2	2	2	2
Total fixed charges and preferred dividends combined	**$ 277**	$ 302	$ 280	$ 307	$ 226
Ratio of Earnings to Fixed Charges	**2.75**	3.39	3.32	2.76	3.00
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**2.73**	3.36	3.29	2.75	2.98

(a) Prior periods have been revised primarily to include purchased power agreements classified as leases in the estimate of interest within rental expense.
(b) Excludes equity costs related to allowance for equity funds used during construction that are included in other income (expense) on the Statements of Income.

Exhibit No. 21

PROGRESS ENERGY, INC.
List of Subsidiaries

The following is a list of certain direct and indirect subsidiaries of Progress Energy, Inc., and their respective states of incorporation as of December 31, 2011. All other subsidiaries, if considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	North Carolina
Florida Progress Corporation	Florida
Florida Power Corporation d/b/a/ Progress Energy Florida, Inc.	Florida

Exhibit No. 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-70332 on Form S-8, Registration Statement No. 333-78157 on Form S-4, Registration Statement No. 333-104951 on Form S-8, Registration Statement No. 333-104952 on Form S-8, Registration Statement No. 333-155541 on Form S-8, Registration Statement No. 333-155543 on Form S-8 and Registration Statement No. 333-178020 on Form S-3 of our reports dated February 28, 2012, relating to the consolidated financial statements and consolidated financial statement schedule of Progress Energy, Inc. and subsidiaries (the "Company"), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2011.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2012

Exhibit No. 31(a)

CERTIFICATION

I, William D. Johnson, certify that:

1. I have reviewed this Annual Report on Form 10-K of Progress Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

By: /s/ William D. Johnson
William D. Johnson
Chairman, President and Chief Executive Officer

Exhibit No. 31(b)

CERTIFICATION

I, Mark F. Mulhern, certify that:

5. I have reviewed this Annual Report on Form 10-K of Progress Energy, Inc.;

6. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

7. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

8. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   e) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   f) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   g) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   h) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

6. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   c) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   d) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and Chief Financial Officer

Exhibit No. 31(c)

CERTIFICATION

I, Lloyd M. Yates, certify that:

1. I have reviewed this Annual Report on Form 10-K of Carolina Power & Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    i) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    j) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    k) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    l) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

7. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    e) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    f) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

By: /s/ Lloyd M. Yates
Lloyd M. Yates
President and Chief Executive Officer

Exhibit No. 31(d)

CERTIFICATION

I, Mark F. Mulhern, certify that:

5. I have reviewed this Annual Report on Form 10-K of Carolina Power & Light Company;

6. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

7. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

8. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   m) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   n) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   o) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   p) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

8. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   g) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   h) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and Chief Financial Officer

Exhibit No. 31(e)

CERTIFICATION

I, Vincent M. Dolan, certify that:

1. I have reviewed this Annual Report on Form 10-K of Florida Power Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   q) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   r) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   s) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   t) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

9. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   i) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   j) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

By: /s/ Vincent M. Dolan
Vincent M. Dolan
President and Chief Executive Officer

Exhibit No. 31(f)

CERTIFICATION

I, Mark F. Mulhern, certify that:

5. I have reviewed this Annual Report on Form 10-K of Florida Power Corporation;

6. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

7. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

8. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   u) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   v) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   w) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   x) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

10. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   k) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   l) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and Chief Financial Officer

Exhibit No. 32(a)

CERTIFICATION FURNISHED PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Progress Energy, Inc. (the "Company") for the period ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, William D. Johnson, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ William D. Johnson
William D. Johnson
Chairman, President and Chief Executive Officer
February 28, 2012

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

CERTIFICATION FURNISHED PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Progress Energy, Inc. (the “Company”) for the period ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Mark F. Mulhern, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and Chief Financial Officer
February 28, 2012

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit No. 32(c)

CERTIFICATION FURNISHED PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Carolina Power & Light Company (the "Company") for the period ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Lloyd M. Yates, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Lloyd M. Yates
Lloyd M. Yates
President and Chief Executive Officer
February 28, 2012

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit No. 32(d)

CERTIFICATION FURNISHED PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Carolina Power & Light Company (the "Company") for the period ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark F. Mulhern, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and Chief Financial Officer
February 28, 2012

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit No. 32(e)

CERTIFICATION FURNISHED PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Florida Power Corporation (the "Company") for the period ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Vincent M. Dolan, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

U/s/ Vincent M. Dolan
Vincent M. Dolan
President and Chief Executive Officer
February 28, 2012

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

**CERTIFICATION FURNISHED PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of Florida Power Corporation (the "Company") for the period ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark F. Mulhern, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and Chief Financial Officer
February 28, 2012

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Progress Energy

Carolina Power & Light Company
410 S. Wilmington Street
Raleigh, NC 27601-1849

March 30, 2012

Dear Shareholder:

I am pleased to invite you to attend the 2012 Annual Meeting of the Shareholders of Carolina Power & Light Company, which will be held on May 7, 2012 at 9:00 a.m. This year, our Annual Meeting will be a completely virtual meeting of shareholders and will be conducted via live webcast on the Internet. You will be able to attend the Annual Meeting online, and submit your questions during the meeting by visiting *www.media-server.com/m/p/q2v8ud37*.

As described in the accompanying Notice of Annual Meeting of Shareholders and Proxy Statement, the matters scheduled to be acted upon at the meeting for Carolina Power & Light Company are the election of eight (8) directors; an advisory (nonbinding) vote on executive compensation; and the ratification of the selection of the independent registered public accounting firm for Carolina Power & Light Company.

Regardless of the size of your holdings, it is important that your shares be represented at the meeting. WHETHER OR NOT YOU PLAN TO ATTEND THE MEETING ONLINE, PLEASE COMPLETE, SIGN AND RETURN THE ENCLOSED PROXY CARD IN THE ACCOMPANYING ENVELOPE OR VOTE BY TELEPHONE IN ACCORDANCE WITH THE INSTRUCTIONS ON THE ENCLOSED PROXY CARD AS SOON AS POSSIBLE. Voting by either of these methods will ensure that your vote is counted at the Annual Meeting if you do not attend the meeting online.

I am delighted that you have chosen to invest in Carolina Power & Light Company and look forward to your participation in the meeting. On behalf of the management and directors of Carolina Power & Light Company, thank you for your continued support and confidence in 2012.

Sincerely,

William D. Johnson

William D. Johnson
Chairman of the Board

VOTING YOUR PROXY IS IMPORTANT

Your vote is important. Please promptly **SIGN, DATE and RETURN** the enclosed proxy card or **VOTE BY TELEPHONE** in accordance with the instructions on the enclosed proxy card so that as many shares as possible will be represented at the Annual Meeting.

A self-addressed envelope, which requires no postage if mailed in the United States, is enclosed for your convenience.

CAROLINA POWER & LIGHT COMPANY

d/b/a Progress Energy Carolinas, Inc.
410 S. Wilmington Street
Raleigh, North Carolina 27601-1849

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE ANNUAL MEETING OF SHAREHOLDERS TO BE HELD ON

MAY 7, 2012

This notice, along with our Proxy Statement and Annual Report to Shareholders, is available at *www.progress-energy.com/proxy.*

The Annual Meeting of the Shareholders of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (the "Company") will be held at 9:00 a.m. on May 7, 2012, via live webcast on the Internet at *www.media-server.com/m/p/q2v8ud37*.

The meeting will be held in order to:

(1) Elect eight (8) directors of the Company, each to serve a one-year term. The Board of Directors recommends a vote **FOR** each of the nominees for director.

(2) Vote on an advisory (nonbinding) proposal to approve executive compensation. The Board of Directors recommends a vote **FOR** this proposal.

(3) Ratify the selection of Deloitte & Touche LLP as the independent registered public accounting firm for the Company. The Board of Directors recommends a vote **FOR** the ratification of the selection of Deloitte & Touche LLP as the Company's independent registered public accounting firm.

(4) Transact any other business as may properly be brought before the meeting.

All holders of the Company's $5 Preferred Stock, Serial Preferred Stock and Common Stock of record at the close of business on March 2, 2012, are entitled to attend the meeting and to vote. The stock transfer books will remain open.

By order of the Board of Directors

David B. Fountain
Corporate Secretary

Raleigh, North Carolina
March 30, 2012

PROXY STATEMENT
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CAROLINA POWER & LIGHT COMPANY

d/b/a Progress Energy Carolinas, Inc.
410 S. Wilmington Street
Raleigh, North Carolina 27601-1849

PROXY STATEMENT
GENERAL

This Proxy Statement is furnished in connection with the solicitation by the Board of Directors (at times referred to as the "Board") of proxies to be used at the Annual Meeting of Shareholders. That meeting will be held at 9:00 a.m. on May 7, 2012, via live webcast at *www.media-server.com/m/p/q2v8ud37*. Throughout this Proxy Statement, Carolina Power & Light Company is at times referred to as "we," "our," "us" or "PEC" and our parent company, Progress Energy, Inc., is referred to as "Progress Energy" or the "Parent." This Proxy Statement and form of proxy were first sent to shareholders on or about March 30, 2012.

An audio webcast of the Annual Meeting of Shareholders will be available online in Windows Media Player format at *www.progress-energy.com/investor*. The webcast will be archived on the site for three months following the date of the meeting.

A copy of our Annual Report on Form 10-K for the year ended December 31, 2011, including financial statements and schedules, is attached to this Proxy Statement. Additional copies are available upon written request, without charge, to the persons whose proxies are solicited. Any exhibit to the Form 10-K is also available upon written request at a reasonable charge for copying and mailing. Written requests should be made to Ms. Sherri L. Green, Treasurer, Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551. Our Form 10-K is also available through the Securities and Exchange Commission's (the "SEC") website at *www.sec.gov* or through our website at *www.progress-energy.com/investor*. The contents of these websites are not, and shall not be deemed to be, a part of this Proxy Statement or proxy solicitation materials.

We have adopted a procedure approved by the SEC called "householding." Under this procedure, shareholders of record who have the same address and last name will receive only one copy of our Proxy Statement and Annual Report, unless one or more of the shareholders at that address notify us that they wish to continue receiving individual copies. We believe this procedure provides greater convenience for our shareholders and saves money by reducing our printing and mailing costs and fees.

If you prefer to receive a separate copy of our Proxy Statement and Annual Report, please write to Shareholder Relations, Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551 or telephone our Shareholder Relations Section at 919-546-3014, and we will promptly send you a separate copy. If you are currently receiving multiple copies of the Proxy Statement and Annual Report at your address and would prefer that a single copy be delivered there, you may contact us at the address or telephone number provided in this paragraph.

PROXIES

The accompanying proxy is solicited by our Board of Directors, and we will bear the entire cost of solicitation. We expect to solicit proxies primarily by mail. Proxies may also be solicited by telephone, email or other electronic media or personally by our and our affiliates' officers and employees, who will not be specially compensated for such services.

You may vote shares either during the meeting or by duly authorized proxy. In addition, you may vote your shares by telephone by following the instructions provided on the enclosed proxy card. The telephone voting facilities for shareholders of record will close at 10:00 a.m. on the day of the meeting. Any shareholder who has executed a proxy and attends the meeting online may elect to vote during the meeting rather than by proxy. You may revoke any proxy given by you in response to this solicitation at any time before the proxy is exercised by (i) delivering a written notice of revocation to our Corporate Secretary, (ii) timely filing, with our Corporate Secretary, a subsequently dated, properly executed proxy, or (iii) attending the Annual Meeting online and electing to vote at that time. Your participation in the Annual Meeting, by itself, will not constitute a revocation of a proxy. If you vote by telephone, you may also revoke your vote by any of the three methods noted above, or you may change your vote by voting again by telephone. If you decide to vote by completing and mailing the enclosed proxy card, you should retain a copy of certain identifying information found on the proxy card in the event that you decide later to change or revoke your proxy. You should address any written notices of proxy revocation to: Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551, Attention: Corporate Secretary.

All shares represented by effective proxies received by the Company at or before the Annual Meeting, and not revoked before they are exercised, will be voted in the manner specified therein. Executed proxies that do not contain voting instructions will be voted **"FOR"** the election of all directors as set forth in this Proxy Statement; **"FOR"** the proposal approving the Company's executive compensation, as set forth in this Proxy Statement; and **"FOR"** the ratification of the selection of Deloitte & Touche LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2012, as set forth in this Proxy Statement. Proxies will be voted at the discretion of the named proxies on any other business properly brought before the meeting.

Special Note for Shares Held in "Street Name"

If your shares are held by a brokerage firm, bank or other nominee (i.e., in "street name"), you will receive directions from your nominee that you must follow in order to have your shares voted. "Street name" shareholders who wish to attend and vote during the online meeting will need to obtain a special proxy form from the brokerage firm, bank or other nominee that holds their shares of record. You should contact your brokerage firm, bank or other nominee for details regarding how you may obtain this special proxy form.

If your shares are held in "street name" and you do not give instructions as to how you want your shares voted (a "nonvote"), the brokerage firm, bank or other nominee who holds the Company's shares on your behalf may vote the shares at its discretion on "routine" matters only. However, such brokerage firm, bank or other nominee is not required to vote your shares and therefore these unvoted shares would be counted as "broker nonvotes."

With respect to "routine" matters, such as the ratification of the selection of the independent registered public accounting firm, a brokerage firm, bank or other nominee has authority (but is not required), under the rules governing self-regulatory organizations (the "SRO rules"), to vote its clients' shares if the clients do not provide instructions. When a brokerage firm, bank or other nominee votes its clients' securities on routine matters without receiving voting instructions, these shares are counted both for establishing a quorum to conduct business at the meeting and in determining the number of shares voted **"FOR"** or **"AGAINST"** such routine matters. The New York Stock Exchange ("NYSE") recently amended its rules to further restrict the ability of brokers to vote on certain types of management-supported corporate governance proposals without specific client instructions. The NYSE had previously amended its rules to make any matter relating to executive compensation a “nonroutine” matter. Matters relating to executive compensation include advisory votes to approve the compensation of executives and to determine how frequently to hold an advisory vote to approve executive compensation.

With respect to “nonroutine” matters, including the election of directors, matters relating to executive compensation and shareholder proposals, a brokerage firm, bank or other nominee is not permitted under the SRO rules to vote its clients’ shares if the clients do not specifically instruct their brokerage firm, bank or other nominee on how to vote their shares. The brokerage firm, bank or other nominee will so note on the vote card, and this constitutes a “broker nonvote.” “Broker nonvotes” will be counted for purposes of establishing a quorum to conduct business at the meeting but not for determining the number of shares voted **“FOR,” “AGAINST”** or **“ABSTAINING”** from such nonroutine matters. At the 2012 Annual Meeting of Shareholders, the following two nonroutine matters will be presented for a vote: the election of eight (8) directors of the Company with terms expiring in 2013; and an advisory (nonbinding) vote on executive compensation.

Accordingly, if you do not vote your proxy, your brokerage firm, bank or other nominee may either: (i) vote your shares on routine matters and cast a “broker nonvote” on nonroutine matters, or (ii) leave your shares unvoted altogether. Therefore, we encourage you to provide instructions to your brokerage firm, bank or other nominee by voting your proxy. This action ensures that your shares and voting preferences will be fully represented at the meeting.

VOTING SECURITIES

Our directors have fixed March 2, 2012, as the record date for shareholders entitled to vote at the Annual Meeting. Only holders of our $5 Preferred Stock, Serial Preferred Stock and Common Stock (collectively referred to as “shares”) of record at the close of business on that date are entitled to notice of and to vote at the Annual Meeting. Each share is entitled to one vote. As of March 2, 2012, there were outstanding 236,997 shares of $5 Preferred Stock, 349,850 shares of Serial Preferred Stock and 159,608,055 shares of Common Stock. Progress Energy owns all outstanding shares of our Common Stock.

Consistent with state law and our By-Laws, the presence, in person or by proxy, of holders of at least a majority of the total number of shares entitled to vote is necessary to constitute a quorum for the transaction of business at the Annual Meeting. Once a share is represented for any purpose at a meeting, it is deemed present for quorum purposes for the remainder of the meeting and any adjournment thereof, unless a new record date is or must be set in connection with any adjournment. Shares held of record by shareholders or their nominees who do not vote by proxy or attend the live webcast of the Annual Meeting will not be considered present or represented at the Annual Meeting and will not be counted in determining the presence of a quorum. Proxies that withhold authority or reflect abstentions or “broker nonvotes” will be counted for purposes of determining whether a quorum is present.

Pursuant to the provisions of the North Carolina Business Corporation Act, directors will be elected by a plurality of the votes cast by the holders of shares entitled to vote. Accordingly, assuming a quorum is present, the nominee(s) receiving the highest number of **“FOR”** votes will be elected. Withheld votes or shares held in “street name” that are not voted in the election of directors will not be included in determining the number of votes cast. Progress Energy intends to vote all of its shares of Common Stock **“FOR”** each nominee.

Approval of an advisory (nonbinding) proposal regarding executive compensation as disclosed in this Proxy Statement will require the affirmative vote of a majority of votes actually cast by the holders of shares entitled to vote. Assuming a quorum is present, the number of **“FOR”** votes cast for this proposal at the meeting must exceed the number of **“AGAINST”** votes cast at the meeting in order for this proposal to be approved. Abstentions from voting and “broker nonvotes” will not count as votes cast and will not have the effect of a “negative” vote with respect to the vote on this proposal. Progress Energy intends to vote all of its shares of Common Stock **“FOR”** this proposal.

Approval of the proposal to ratify the selection of our independent registered public accounting firm, and other matters properly brought before the Annual Meeting, if any, generally will require the affirmative vote of a majority of votes actually cast by holders of shares entitled to vote. Assuming a quorum is present, the number of **"FOR"** votes cast at the meeting for this proposal must exceed the number of **"AGAINST"** votes cast at the meeting in order for the proposal to be approved. Abstentions from voting and "broker nonvotes" will not count as votes cast and will not have the effect of a "negative" vote with respect to any such matters. Progress Energy intends to vote all of its shares of Common Stock **"FOR"** this proposal.

We will announce preliminary voting results at the conclusion of the Annual Meeting. We will publish the final results in a Current Report on Form 8-K within four (4) business days of the Annual Meeting. A copy of this Form 8-K may be obtained without charge by any of the means outlined above for obtaining a copy of our Annual Report on Form 10-K.

PROPOSAL 1—ELECTION OF DIRECTORS

The Company's amended By-Laws provide that the number of directors of the Company shall be not less than five nor more than nine. The amended By-Laws also provide for the annual election of each director. Directors will serve one-year terms upon election at the 2012 Annual Meeting of Shareholders.

The Board of Directors nominates the following eight (8) nominees to serve as directors with terms expiring in 2013 and until their respective successors are elected and qualified: Jeffrey A. Corbett, William D. Johnson, Jeffrey J. Lyash, John R. McArthur, Mark F. Mulhern, James Scarola, Paula J. Sims, and Lloyd M. Yates. Proxies cannot be voted for a greater number of persons than nominees named.

There are no family relationships between any of the directors, any executive officers or nominees for director of the Company or its subsidiaries, and there is no arrangement or understanding between any director or director nominee and any other person pursuant to which the director or director nominee was selected.

The election of directors will be determined by a plurality of the votes cast at the Annual Meeting at which a quorum is present. This means that nominees receiving the highest number of **"FOR"** votes will be elected. Abstentions and broker nonvotes, if any, are not treated as votes cast and, therefore, will have no effect on the proposal to elect directors. Shareholders do not have cumulative voting rights in connection with the election of directors.

Valid proxies received pursuant to this solicitation will be voted in the manner specified. Where specifications are not made, the shares represented by the accompanying proxy will be voted **"FOR"** the election of each of the eight (8) nominees. Votes (other than abstentions) will be cast pursuant to the accompanying proxy for the election of the nominees listed above unless, by reason of death or other unexpected occurrence, one or more of such nominees shall not be available for election, in which event it is intended that such votes will be cast for such substitute nominee or nominees as may be determined by the persons named in such proxy. The Board of Directors has no reason to believe that any of the nominees listed above will not be available for election as a director.

The names of the eight (8) nominees for election to the Board of Directors, along with their ages, principal occupations or employment for the past five years, directorships of public companies held during the past five years, and disclosures regarding the specific experience, qualifications, attributes or skills that led the Board to conclude that such individuals should serve on the Board, are set forth below. The Board has not established any committees. The Company is a direct subsidiary of Progress Energy and an affiliate of Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), which is noted in the descriptions below. Information concerning the number of shares of Progress Energy's Common Stock beneficially owned, directly or indirectly, by all current directors appears on page 8 of this Proxy Statement.

The Board of Directors recommends a vote **"FOR"** each nominee for director.

Nominees for Election

JEFFREY A. CORBETT, age 52, is Senior Vice President, Energy Delivery, of the Company, since January 2008. In his current role, Mr. Corbett oversees operations and services in the Carolinas, including engineering, distribution, construction, metering, power restoration, community relations and customer service. He has served as a director of the Company since 2008. Mr. Corbett previously served as Senior Vice President, Energy Delivery, of PEF, from June 2006 to January 2008; Vice President, Distribution, of the Company, from January 2005 to June 2006; Vice President, Eastern Region, of the Company, from September 2002 to January 2005; General Manager, Eastern Region, of the Company, from January 2001 to August 2002; and Director, Distribution Power Quality and Reliability, from 1999 to December 2000. Before joining Progress Energy in 1999, Mr. Corbett spent 17 years with Virginia Power, serving in a variety of engineering and leadership roles. Mr. Corbett's broad experience and knowledge in operations, customer service, energy efficiency and demand-side management will be critical assets as the Company pursues its strategy of undertaking the long-range investments and initiatives necessary to meet the growing energy needs of our customers, control costs and comply with public policies while creating long-term value.

WILLIAM D. JOHNSON, age 58, is Chairman, President and Chief Executive Officer of Progress Energy, since October 2007. Mr. Johnson is also Chairman of PEC and PEF. He has served as Chairman of the Company since July 2007. Mr. Johnson previously served as President and Chief Operating Officer of Progress Energy, from January 2005 to October 2007. In that role, he oversaw the generation and delivery of electricity by PEC and PEF. Mr. Johnson has been with Progress Energy (formerly CP&L) in a number of roles since 1992, including Group President for Energy Delivery, President and Chief Executive Officer for Progress Energy Service Company, LLC and General Counsel and Corporate Secretary for Progress Energy. Before joining Progress Energy, Mr. Johnson was a partner with the Raleigh, N.C., law office of Hunton & Williams LLP, where he specialized in the representation of utilities. Mr. Johnson has served in a variety of senior management positions during his tenure with the Company. His background as a lawyer representing utilities, coupled with his years of hands-on experience at the Company, provides him with a unique perspective and a keen understanding of the opportunities and challenges facing the Company and our industry. Mr. Johnson's breadth of knowledge and experience in addressing key operational, policy, legislative and strategic issues, and his proven leadership skills will be significant assets to the Company as it focuses on optimizing its balanced solution strategy for meeting our customers' growing energy needs and complying with public policies in the face of a challenging economy, and a changing regulatory and legislative environment.

JEFFREY J. LYASH, age 50, is Executive Vice President, Energy Supply, of Progress Energy, since June 2010. In his role, Mr. Lyash oversees Progress Energy's diverse fleet of generating resources, including nuclear, coal, oil, natural gas and hydroelectric stations. In addition, he oversees fuel procurement for our generating fleet and the Company's power trading operations. Mr. Lyash has served as Executive Vice President and as a director of the Company since 2009. He previously served as Executive Vice President of Corporate Development, Progress Energy, from July 2009 to June 2010; President and Chief Executive Officer, PEF, from June 2006 to July 2009; Senior Vice President, PEF, from November 2003 to June 2006; and Vice President, Transmission in Energy Delivery, PEC, from January 2002 to October 2003. Mr. Lyash joined Progress Energy (formerly CP&L) in 1993 and spent his first eight years at the Brunswick Nuclear Plant in Southport, N.C., in a number of management roles. His last position at Brunswick was as Director of site operations. Before joining Progress Energy, Mr. Lyash worked for the U.S. Nuclear Regulatory Commission (NRC) between 1984 and 1993 in a number of senior technical and management positions. Mr. Lyash's breadth of experience and leadership abilities will continue to be valuable in the Company's efforts to make the investments necessary to optimize its balanced solution strategy for meeting the future energy needs of its customers, controlling costs and satisfying public policies in a challenging economy and changing business environment.

JOHN R. MCARTHUR, age 56, is Executive Vice President of Progress Energy, since September 2008. In that role, Mr. McArthur is responsible for corporate and utility support functions, including Audit Services, Corporate Communications, Corporate Services, External Relations, Human Resources and Legal. He has served as a director of the Company since 2007. Mr. McArthur also serves as General Counsel, since April 2010, and previously from 2004 until 2009, and as Corporate Secretary of Progress Energy since 2004. He is also Executive Vice President of the Company since September 2008, Executive Vice President of PEF since November 2008 and Executive Vice President of Florida Progress Corporation since January 2010. Mr. McArthur has been with Progress Energy in a number of roles since 2001, including Senior Vice President, Corporate Relations, and Vice President, Public Affairs. Before joining Progress Energy, he was a senior adviser to N.C. Governor Mike Easley, handling major policy initiatives as well as media and legal affairs. Mr. McArthur's extensive legal, policy and legislative experience will be critical assets to the Company as we optimize our balanced solution strategy of investments and initiatives that meet customers' growing energy needs and comply with public policies, while creating long-term value.

MARK F. MULHERN, age 52, is Senior Vice President and Chief Financial Officer of the Company, PEF and Progress Energy, since September 2008. Mr. Mulhern has served as a director of the Company since 2008. He previously served as Senior Vice President, Finance, of the Company and PEF, from November 2007 to September 2008, and Senior Vice President, Finance, of Progress Energy, from July 2007 to September 2008. Mr. Mulhern also served as President of Progress Ventures (the unregulated subsidiary of Progress Energy), from 2005 to 2008; Senior Vice President of Competitive Commercial Operations of Progress Ventures, from 2003 to 2005; Vice President, Strategic Planning, of Progress Energy, from 2000 to 2003; Vice President and Treasurer of Progress Energy, from 1997 to 2000; and Vice President and Controller of Progress Energy, from 1996 to 1997. Before joining Progress Energy (formerly CP&L) in 1996, Mr. Mulhern was the Chief Financial Officer at Hydra Co. Enterprises, the independent power subsidiary of Niagara Mohawk. He also spent eight years at Price Waterhouse, serving a wide variety of manufacturing and service businesses. Mr. Mulhern has worked in every financial management function at Progress Energy. He understands the Company and our industry. Mr. Mulhern's experience and qualifications in corporate finance will be important to the Company's efforts to meet its financial commitments and attract capital for funding the investments and initiatives necessary to implement the Company's balanced solution strategy, while creating long-term value in a challenging economy and changing business environment.

Other public directorships in past five years:
EXCO Resources, Inc. (February 2010 to present)
Highwoods Properties, Inc. (January 2012 to present)

JAMES SCAROLA, age 56, is Senior Vice President and Chief Nuclear Officer of the Company and PEF, since January 2008. In that role, he oversees all aspects of the Company's nuclear program. Mr. Scarola has served as a director of the Company since 2008. He previously served as Vice President at the Brunswick Nuclear Plant, from October 2005 to December 2007. Mr. Scarola joined Progress Energy (formerly CP&L) in 1998, where he served as Vice President at the Harris Nuclear Power Plant until October 2005. Mr. Scarola entered the nuclear power field in 1978 as a design engineer and has held positions in construction, start-up testing, maintenance, engineering and operations. Prior to joining Progress Energy, he was the General Manager of Florida Power & Light Company's St. Lucie Nuclear Plant. Mr. Scarola has served in leadership positions at the Company at the plant level and throughout Progress Energy's Nuclear Generation Group. He has been instrumental in developing a culture of performance. Mr. Scarola's extensive technical knowledge and proven capabilities in the nuclear arena will be an asset in the years ahead, as the Company focuses on improving nuclear fleet performance and optimizing its balanced solution to meeting its customers' growing electric energy needs, controlling costs and complying with public policies while creating long-term value.

PAULA J. SIMS, age 50, is Senior Vice President, Corporate Development and Improvement, of Progress Energy, since June 2010. In this role, Ms. Sims is responsible for implementing our balanced solution strategy for meeting the future energy needs of our customers. In addition, she oversees program development and construction of new generation projects, renewable energy and energy-efficiency programs, supply chain, information technology and wholesale power operations. Ms. Sims is the executive sponsor for Continuous Business Excellence, Progress Energy's framework for improving processes, efficiency and overall cost management, and has responsibility for environmental, health and safety. She has served as a director of the Company since 2008. Ms. Sims previously served as Senior Vice President, Power Operations, of the Company and PEF, from July 2007 to June 2010; Senior Vice President, Regulated Services, of the Company, from January 2006 to July 2007; Vice President, Fossil Fuel Generation, of the Company and PEF, from January 2006 to April 2006; Vice President, Regulated Fuels, of the Company, from December 2004 to December 2005; Chief Operating Officer of Progress Fuels Corporation, from February 2002 to December 2004; and Vice President, Business Operations & Strategic Planning, of Progress Fuels Corporation, from June 2001 to February 2002. Before joining Progress Energy in 1999, Ms. Sims was with GE Aircraft Engines, where she served in a number of engineering, operations and plant management roles for over 15 years. Ms. Sims' depth of knowledge and experience will continue to be valuable to the Company as it navigates a challenging economy and changing business environment. Ms. Sims' leadership in creating a culture focused on improving efficiency and service while achieving sustainable savings will be important to the Company's efforts to meet its financial commitments and attract the capital necessary for optimizing its balanced solution strategy for meeting customer needs and complying with public policies, while creating long-term value.

LLOYD M. YATES, age 51, is President and Chief Executive Officer of the Company, since July 2007. Mr. Yates is responsible for overseeing the overall strategic direction and financial performance of the Company. He also oversees all aspects of the Company's delivery operations, including distribution and customer service, transmission, and products and services. Mr. Yates has served as director of the Company since 2007. He served as Senior Vice President of the Company, from January 2005 to July 2007; Vice President, Transmission, from November 2003 to December 2004; and Vice President, Fossil Generation, from November 1998 to November 2003. Before joining Progress Energy (formerly CP&L) in 1998, Mr. Yates was with PECO Energy for over 16 years in several line operations and management positions. Mr. Yates's vast experience and knowledge of the Company and our industry will continue to be significant assets as the Company optimizes its balanced solution strategy for meeting its customers' future energy needs by combining energy-efficiency programs, alternative and renewable energy and a state-of-the-art power system. Mr. Yates has the proven leadership skills the Company will need as it seeks to create long-term value as it confronts a challenging economy, a complex business environment, and a changing regulatory landscape.

Other public directorships in past five years:
Marsh & McLennan Companies, Inc. (May 2011 to present)

PRINCIPAL SHAREHOLDERS

The table below sets forth the only shareholders we know to beneficially own more than 5 percent (5%) of the outstanding shares of our Common Stock as of February 29, 2012. We are not aware of any person owning more than 5 percent (5%) of either our $5 Preferred Stock or our Serial Preferred Stock. Other than the previously noted three classes of stock, we do not have any other class of voting securities outstanding.

Title of Class	Name and Address of Beneficial Owner	Number of Shares Beneficially Owned	Percentage of Class
Common Stock	Progress Energy, Inc. 410 S. Wilmington Street Raleigh, NC 27601-1849	159,608,055	100

MANAGEMENT OWNERSHIP OF COMMON STOCK

None of our Directors or Officers owns any of the Company's Common Stock or either series of our Preferred Stock.

The following table describes the beneficial ownership of the Common Stock of Progress Energy as of February 29, 2012, of (i) all current directors and nominees for director, (ii) each executive officer named in the Summary Compensation Table presented later in this Proxy Statement, and (iii) all directors and nominees for director and executive officers as a group. As of February 29, 2012, none of the individuals or the group in the above categories owned 1 percent (1%) or more of Progress Energy's voting securities. Unless otherwise noted, all shares of Progress Energy Common Stock set forth in the table are beneficially owned, directly or indirectly, with sole voting and investment power, by such shareholder.

Name	Number of Shares of Common Stock Beneficially Owned
Jeffrey A. Corbett	25,772
William D. Johnson	240,142
Jeffrey J. Lyash	28,087
John R. McArthur	76,535
Mark F. Mulhern	51,918
James Scarola	5,183
Paula J. Sims	33,360
Lloyd M. Yates	51,837
Shares of Progress Energy Common Stock beneficially owned by all directors and executive officers of the Company as a group (9 persons)	520,822

Management Ownership of Units Representing Common Stock

The table below shows ownership as of February 29, 2012, of (i) performance units recorded to reflect awards deferred under the Progress Energy Management Incentive Compensation Plan ("MICP"); (ii) performance shares awarded under the Performance Share Sub-Plan of Progress Energy's 1997, 2002 and 2007 Equity Incentive Plans ("PSSP") (see "Outstanding Equity Awards at 2011 Fiscal Year-End Table" on page 42); (iii) units recorded to reflect awards deferred under the PSSP; (iv) replacement units representing the value of our contributions to the Progress Energy 401(k) Savings & Stock Ownership Plan that would have been made but for the deferral of salary under Progress Energy's Management Deferred Compensation Plan and contribution limitations under Section 415 of the Internal Revenue Code of 1986, as amended; and (v) Restricted Stock Units ("RSUs") awarded under the 2002 and 2007 Progress Energy Equity Incentive Plans. A unit of Common Stock does not represent an equity interest in Progress Energy, and possesses no voting rights, but is equal in economic value at all times to one share of Progress Energy Common Stock.

Officer	MICP	PSSP	PSSP Deferred	MDCP	RSUs
William D. Johnson	1,890	117,490	—	1,170	73,938
Jeffrey L. Lyash	—	26,996	—	3,898	19,195
John R. McArthur	—	29,083	—	—	19,999
Mark F. Mulhern	949	26,030	—	—	18,765
Lloyd M. Yates	2,952	26,699	7,043	175	19,066

CHANGES IN CONTROL

On January 8, 2011, Duke Energy Corporation ("Duke Energy") and our Parent entered into a Merger Agreement, pursuant to which our Parent will be acquired by Duke Energy in a stock-for-stock transaction and become a wholly owned subsidiary of Duke Energy (the "Merger"). Both companies' shareholders have approved the Merger. However, consummation of the Merger is subject to customary conditions, including, among other things, expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and receipt of approval, to the extent required, from the Federal Energy Regulatory Commission, the Federal Communications Commission, the Nuclear Regulatory Commission, the North Carolina Utilities Commission, the Kentucky Public Service Commission, and the South Carolina Public Service Commission. Although there are no merger-specific regulatory approvals required in Indiana, Ohio or Florida, the companies will continue to update the public service commissions in those states on the Merger, as applicable and as required.

TRANSACTIONS WITH RELATED PERSONS

There were no transactions in 2011 and there are no currently proposed transactions involving more than $120,000 in which the Company or any of its subsidiaries was or is to be a participant and in which any of the Company's directors, executive officers, nominees for director or any of their immediate family members had a direct or indirect material interest except for compensation earned pursuant to their employment agreements for services they provide to the Company and its affiliates.

Our Parent's Board of Directors has adopted policies and procedures for the review, approval or ratification of Related Person Transactions under Item 404(a) of Regulation S-K (the "Policy"), which is attached to this Proxy Statement as Exhibit A. Progress Energy's Board has determined that its Corporate Governance Committee (the "Governance Committee") is best suited to review and approve Related Person Transactions because that Committee oversees Progress Energy's Board of Directors' assessment of its directors' independence. Progress Energy's Governance Committee will review and may recommend to the Board amendments to this Policy from time to time.

For the purposes of the Policy, a "Related Person Transaction" is a transaction, arrangement or relationship, including any indebtedness or guarantee of indebtedness (or any series of similar transactions, arrangements or relationships), in which Progress Energy (including any of its subsidiaries) was, is or will be a participant and the amount involved exceeds $120,000, and in which any Related Person had, has or will have a direct or indirect material interest. The term "Related Person" is defined under the Policy to include our directors, executive officers, nominees to become directors and any of their immediate family members.

Progress Energy's general policy is to avoid Related Person Transactions. Nevertheless, Progress Energy recognizes that there are situations where Related Person Transactions might be in, or might not be inconsistent with, our best interests and those of our shareholders. These situations could include (but are not limited to) situations where we might obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when we provide products or services to Related Persons on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. In determining whether to approve or disapprove each Related Person Transaction, the Governance Committee considers various factors, including (i) the identity of the Related Person; (ii) the nature of the Related Person's interest in the particular transaction; (iii) the approximate dollar amount involved in the transaction; (iv) the approximate dollar value of the Related Person's interest in the transaction; (v) whether the Related Person's interest in the transaction conflicts with his obligations to the Company and its shareholders; (vi) whether the transaction will provide the Related Person with an unfair advantage in his dealings with the Company; and (vii) whether the transaction will affect the Related Person's ability to act in the best interests of the Company and its shareholders. The Governance Committee will approve only those Related Person Transactions that are in, or are not inconsistent with, the best interests of the Company and its shareholders.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934 requires our directors and executive officers to file reports of their holdings and transactions in our securities and those of our Parent with the SEC and the NYSE. Based on our records and other information, we believe that all Section 16(a) filing requirements applicable to our directors and executive officers with respect to the Company's 2011 fiscal year were met, except as follows: Jeffrey M. Stone inadvertently failed to file on a timely basis a Form 4 with respect to an ad hoc restricted stock unit award granted under the Progress Energy 2007 Equity Incentive Plan. A Form 4 reporting the transaction was filed on April 12, 2011.

CODE OF ETHICS

In keeping with its commitment to sound corporate governance, the Board of Directors of Progress Energy has adopted a comprehensive written Code of Ethics that incorporates an effective reporting and enforcement mechanism. The Code of Ethics is applicable to all employees of Progress Energy and its subsidiaries, including our Chief Executive Officer, our Chief Financial Officer and our Controller. The Board has adopted Progress Energy's Code of Ethics as its own standard. Board members, our officers and our employees certify their compliance with Progress Energy's Code of Ethics on an annual basis.

Progress Energy's Code of Ethics is posted on our Parent's Internet website and can be accessed at *www.progress-energy.com/investor* and is available in print at no cost to any shareholder upon written request.

Our Parent intends to satisfy the disclosure requirements under Item 5.05 of Form 8-K relating to amendments to or waivers from any provision of the Code of Ethics applicable to our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and Controller by posting such information on its website cited above.

DIRECTOR INDEPENDENCE

The Board of Directors has determined that none of the persons who served as directors for any portion of 2011 was, and none of the current directors or nominees for director is, independent, as that term is defined under the general independence standards contained in the listing standards of the NYSE because they are all employees of the Company and/or its affiliates. Neither the NYSE rules nor the SEC rules require our directors to be independent.

BOARD, BOARD COMMITTEE AND ANNUAL MEETING ATTENDANCE

The Board of Directors is currently comprised of eight (8) members. The Board of Directors met three (3) times in 2011. Average attendance of the directors at the meetings of the Board held in 2011 was 92 percent, and no directors attended less than 100 percent of all Board meetings held in 2011 except for Mr. Scarola, who, due to travel obligations on behalf of the Company, did not attend two of the three meetings that were held. As a result, his average attendance was 33 percent.

Our Company expects all directors to attend its annual meetings of shareholders. All directors who were serving as directors as of May 11, 2011, the date of the 2011 Annual Meeting of Shareholders, attended that meeting.

BOARD COMMITTEES

In conjunction with the restructuring of the Company's Board in 2007 to include only employees of the Company and its affiliates, the Board determined that it was not necessary to establish committees of the Board. Therefore, the Company does not have a separately standing audit committee, compensation committee or nominating committee. The Board believes that this approach increases efficiency and permits the Company to better execute its business strategy.

The full Board participates in the consideration of director nominees.

The Organization and Compensation Committee of Progress Energy's Board of Directors has been delegated authority on behalf of the Company to approve senior management compensation, including making senior executive compensation recommendations to our Board, as appropriate. The following individuals are members of the Organization and Compensation Committee of Progress Energy's Board: Ms. E. Marie McKee—Chair, and Messrs. John D. Baker II, Harris E. DeLoach, Jr., James B. Hyler, Jr., Robert W. Jones, Melquiades R. "Mel" Martinez, and John H. Mullin, III.

The Audit and Corporate Performance Committee of Progress Energy's Board is responsible for the pre-approval of audit and nonaudit services provided to the Company by its independent registered accounting firm. The following individuals are members of the Audit and Corporate Performance Committee of Progress Energy's Board: Ms. Theresa M. Stone—Chair, and Messrs. James E. Bostic, Jr., W. Steven Jones, Charles W. Pryor, Jr., Carlos A. Saladrigas, and Alfred C. Tollison, Jr. Ms. Stone and Mr. Saladrigas have been designated by the Progress Energy Board of Directors as the "Audit Committee Financial Experts," as that term is defined in the SEC rules.

Compensation Committee Interlocks and Insider Participation

The Company's Board does not have a compensation committee. As noted above, the Organization and Compensation Committee of Progress Energy's Board of Directors has been delegated authority on behalf of the Company to approve senior management compensation. William D. Johnson, our Parent's Chief Executive Officer and our Chairman of the Board, is responsible for conducting annual performance evaluations of the other executive officers and making recommendations to the Organization and Compensation Committee of Progress Energy's Board regarding those executives' compensation.

There are no relationships that require disclosure under Item 407(e)(4)(iii) of Regulation S-K.

DIRECTOR NOMINATING PROCESS AND COMMUNICATIONS WITH BOARD OF DIRECTORS

Director Candidate Recommendations and Nominations by Shareholders

Shareholders should submit any director candidate recommendations in writing in accordance with the method described under "Communications with the Board of Directors" below. Any director candidate recommendation that is submitted by one of our shareholders will be acknowledged, in writing, by the Corporate Secretary. The recommendation will be promptly forwarded to the Chairman of the Board, who will place consideration of the recommendation on the agenda for the Board's regular November meeting. The Board will discuss candidates recommended by shareholders at its November meeting, and will determine whether it will nominate a particular candidate for election to the Board.

Additionally, in accordance with Section 10 of our By-Laws, any shareholder of record entitled to vote for the election of directors at the applicable meeting of shareholders may nominate persons for election to the Board of Directors if that shareholder complies with the notice procedure set forth in the By-Laws and summarized in "Future Shareholder Proposals" on page 67 of this Proxy Statement.

Process for Identifying and Evaluating Director Candidates

The full Board evaluates all director candidates, including those nominated or recommended by shareholders, in accordance with the Board's qualification standards. The Board evaluates each candidate's qualifications and assesses them against the perceived needs of the Board. Qualification standards for all Board members include: integrity; sound judgment; financial acumen; strategic thinking; ability to work effectively as a team member; demonstrated leadership; experience in a field of business; professional or other activities that bear a relationship to our mission and operations; appreciation of the business and social environment in which we operate; and an understanding of our responsibilities to shareholders, employees, customers and the communities we serve. The Company does not have a nominating committee.

Communications with the Board of Directors

The Board has approved a process for shareholders to send communications to the Board. That process provides that shareholders can send communications to the Board or to specified individual directors in writing c/o David B. Fountain, Corporate Secretary, Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551.

We screen mail addressed to the Board or any specified individual director for security purposes and to ensure that the mail relates to discrete business matters relevant to the Company. Mail that satisfies these screening criteria is forwarded to the appropriate director.

BOARD DIVERSITY

The Company's Board does not have a separately standing nominating committee. Rather, the full Board participates in the consideration of director nominees. The Board does not have a policy with regard to the consideration of diversity in identifying director nominees; however, diversity and inclusion is an integral part of the Company's culture. The Company recognizes that its success is dependent upon a sound corporate strategy and highly motivated employees who bring diverse perspectives, experiences and abilities to the workplace.

BOARD LEADERSHIP STRUCTURE AND ROLE IN RISK OVERSIGHT

Board Leadership Structure

Our By-Laws require the Board to appoint a Chief Executive Officer who shall also be either the Chairman, the Vice Chairman or the President of the Company. Currently, the Board believes that the Company's interests are best served by separating the roles of Chairman and Chief Executive Officer. William D. Johnson serves as Chairman, and Lloyd M. Yates serves as President and Chief Executive Officer. Although the two roles are separate, the individuals who serve in the roles are both employees of the Company or its affiliates. Indeed, the Company's Board is comprised entirely of employees of the Company or its affiliates. The Company believes that this structure simplifies the decision-making process, increases efficiency and permits the Company to better execute its business strategy. This is particularly beneficial for the Board at this time given the rapidly evolving nature of the energy industry and the complexity of the projects being undertaken by the Company, including the implementation of its coal-to-gas strategy.

As a result of the restructuring of the Company's Board in 2007, none of the current directors is independent, as that term is defined under the general independence standards contained in the listing standards of the NYSE, because they are all employees of the Company or its affiliates. Neither the NYSE rules nor the SEC rules require our directors to be independent. The Company does not have a Lead Director.

Board Role in Risk Oversight

Our Parent has established a framework that supports the risk management activities that occur across Progress Energy, including the Company. The framework establishes processes for identifying, measuring, managing and monitoring risk across our Parent and its subsidiaries. Our Parent also maintains an ongoing oversight structure that details risk types and the internal organizations and Committees of our Parent's Board that have oversight and governance responsibility for each risk type. Progress Energy's Chief Executive Officer and Senior Management have responsibility for assessing and managing the Company's exposure to risk. In this regard, our Parent has established a Risk Management Committee, comprised of various senior executives, that provides guidance and direction in the identification and management of financial risks. The Company's Board is not involved in the Company's day-to-day risk management activities; however, our Parent's Board and its various Committees are involved in different aspects of overseeing those activities.

The risks associated with our strategic plan are discussed annually with Progress Energy's Board. Because overseeing risk is an ongoing process and inherent in our Parent's strategic decisions, Progress Energy's Board also discusses risk throughout the year at other meetings in relation to specific proposed actions.

The Audit and Corporate Performance Committee of Progress Energy's Board is responsible for ensuring that appropriate risk management guidelines and controls are in place and reviews the oversight structure for managing risk. The Audit and Corporate Performance Committee reviews and discusses with management our Parent's guidelines and policies governing risk assessment and risk management. The Audit and Corporate Performance Committee is also responsible for oversight of the risks associated with financial reporting and our Parent's compliance with legal and regulatory requirements.

The Finance Committee of Progress Energy's Board is responsible for the oversight of the Risk Management Committee Policy and Guidelines. It oversees the financial risks associated with guarantees, risk capital, corporate financing activities and debt structure. The Finance Committee ensures that dollar amounts and limits are managed within the established framework. The Finance Committee reports to the full Board of Progress Energy at least once a quarter.

The Operations and Nuclear Oversight Committee of Progress Energy's Board is charged with oversight of risks related to operations, major capital projects and environmental, health and safety issues.

The Organization and Compensation Committee of Progress Energy's Board is responsible for the oversight of risks that can result from personnel issues and misalignment between compensation and performance plans and the interests of Progress Energy's shareholders.

Our Parent's risk management structure is designed to enable Progress Energy's Board to stay informed about and understand the key risks facing the Company, understand how those risks relate to the Company's business and strategy, and the steps our Parent is taking to manage those risks.

COMPENSATION DISCUSSION AND ANALYSIS

This Compensation Discussion and Analysis ("CD&A") relates to the compensation of the executive officers of the Company. The officers of the Company's parent, Progress Energy, Inc. (the "Parent" or "Progress Energy") also serve as officers and/or directors of various Progress Energy subsidiaries, including the Company, in 2011.

The total compensation of Progress Energy's executive officers was designed to cover the full range of services provided to Progress Energy and its subsidiaries. It is not the policy of Progress Energy to allocate compensation paid to its executive officers among the various subsidiaries in which they provide services. The Organization and Compensation Committee of Progress Energy's Board of Directors (throughout this CD&A, the "Committee") is designated authority on behalf of the Company to approve senior management compensation, including making senior executive compensation recommendations to subsidiary boards, as appropriate.

EXECUTIVE SUMMARY

The Company is an integrated electric utility primarily engaged in the regulated utility business. As a wholly owned subsidiary of Progress Energy, our executive compensation philosophy has been aligned with that of our Parent. It is designed to provide competitive compensation consistent with key principles that we believe are critical to our long-term success. The Committee took into account the affirmative shareholder advisory vote on executive compensation at the 2011 Annual Meeting. Because a vast majority (over 99%) of our shareholders approved the compensation described in the proxy statement for the 2011 Annual Meeting, the Committee did not implement changes to our compensation program as a result of the shareholder advisory vote.

We are committed to providing an executive compensation program that supports the following goals and philosophies:

- Aligning our management team's interests with shareholders' expectations of long-term shareholder value, earnings per share growth and a competitive dividend yield;
- Effectively compensating our management team for actual performance over the short and long term;
- Rewarding operating performance results that are sustainable and consistent with safe, reliable and efficient electric service;
- Attracting, engaging and retaining an experienced and effective management team;
- Motivating and rewarding our management team to create shareholder value that is sustainable and consistent with prudent risk-taking and based on sound corporate governance practices; and
- Providing market competitive levels of target (i.e., opportunity) compensation.

Highlights of the 2011 executive compensation program were:

- Our named executive officers' ("NEOs") target (i.e., opportunity) total compensation levels were approximately 24% below the 50^{th} percentile of our benchmarking peer group as described below in the Benchmarking section.
- We continued to provide only minimal executive perquisites (only those prevalent in the marketplace and that are conducive to promoting our desired business outcomes) and no tax gross-ups were made on any perquisites.

- Payments under the Management Incentive Compensation Plan (“MICP”) and the Performance Share Sub-Plan (“PSSP”) were based on the achievement of multiple performance factors that we believe drive shareholder value.

- Based on management’s achievement of key strategic initiatives, the Committee made a number of decisions including:

  - providing on average a 3% merit-based increase;

  - awarding equity grants at target value;

  - awarding ad hoc restricted stock unit (“RSU”) grants to each of the NEOs to, among other things, provide a long-term retention incentive for the pending merger with Duke Energy; and

  - increasing our Chairman’s annual incentive target opportunity from 85% to 100%.

For 2011, the Company’s NEOs were:

- William D. Johnson, Chairman;

- Mark F. Mulhern, Senior Vice President and Chief Financial Officer;

- Jeffrey J. Lyash, Executive Vice President – Energy Supply;

- Lloyd M. Yates, President and Chief Executive Officer; and

- John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary.

I. COMPENSATION OVERVIEW

ASSESSMENT OF RISK

Progress Energy’s subsidiaries, including the Company, are highly regulated at both the federal and state levels. Risks which are undertaken outside the normal course of business are carefully evaluated by senior management and our Parent’s Board of Directors. We believe our compensation program for executive officers does not incentivize excessive risk taking for the following reasons:

- Our compensation program is evaluated annually by the Committee, with the assistance of its compensation consultant, for its effectiveness and consistency with the Company’s goals.

- Our incentive compensation practices do not reward the executive officers for meeting or exceeding volume or revenue targets.

- Our compensation program appropriately balances short- and long-term incentives with approximately 63% of total target compensation for the Chairman and approximately 52% of total target compensation for the other NEOs provided in equity and focused on long-term performance.

- The PSSP rewards significant and sustainable performance over the longer term by focusing on three-year earnings per share growth and three-year relative total shareholder return.

- The MICP focuses on ongoing earnings per share and legal entity net income, as defined in the MICP, because we believe that these measures fundamentally drive shareholder value and the long-term health of our Parent and the Company.

- The executive officers are subject to stock ownership guidelines independently set by the Committee to ensure long-term alignment with shareholders.

- Directors and employees, including the NEOs, are not permitted to enter into hedging transactions involving our stock.

- The Committee has discretion to adjust all incentive awards based on factors it deems appropriate, including the Company's, our Parent's, and the individual executive's performance and how results are achieved.

We have determined that the compensation program for executive officers who are in senior management positions does not encourage excessive risk taking for all the reasons stated above.

PROGRAM ADMINISTRATION

Our executive compensation program was administered by the Committee comprised of seven independent directors (as defined under the NYSE Corporate Governance Rules). The Committee may form and delegate to subcommittees such power and authority as the Committee deems appropriate. Members of the Committee currently have not received compensation under any compensation program in which our executive officers participate. For a discussion of director compensation, see the "Director Compensation" section on page 60 of this Proxy Statement.

The Committee's charter authorizes the Committee to hire outside consultants. The Committee evaluates the performance of its compensation consultant annually to assess the consultant's effectiveness in assisting the Committee with implementing the Company's compensation program and principles. The Committee retained Meridian Compensation Partners, LLC ("Meridian") as its independent executive compensation consultant to assist the Committee in meeting the Company's compensation objectives. The Committee met regularly with its consultant in executive session to discuss matters independent of management. Under the terms of its engagement, in 2011 Meridian reported directly to the Committee. Meridian's only professional service is executive compensation advisory services, which it provided to the Committee. Meridian provided no other services to the Committee or the Company.

Members of management met periodically with the compensation consultant to ensure the consultant understands our business strategy and that of our Parent. On an as-needed basis, our Parent provided the consultant with information regarding our executive compensation and benefit plans and how we administer them. In addition, the executive officers ensured that the Committee received administrative support and assistance, and made recommendations to the Committee to ensure that compensation plans were aligned with our business strategy and met the principles described above. John R. McArthur, our Executive Vice President, served as management's liaison to the Committee. William D. Johnson, our Parent's Chief Executive Officer, is responsible for conducting annual performance evaluations of the other executive officers and making recommendations to the Committee regarding those executives' compensation. The independent directors of our Parent's Board conduct an annual performance evaluation of Mr. Johnson. The Committee discusses the results of the evaluation with Mr. Johnson and makes compensation decisions for him giving consideration to the evaluation results.

COMPETITIVE POSITIONING PHILOSOPHY

The Committee's and our Parent's philosophy is to target the midpoint (i.e., 50th percentile) of the marketplace in setting compensation levels. Also consistent with 50th percentile market practices, it is our philosophy to deliver a preponderance of total compensation to executives in the form of short- and long-term incentive compensation. The Committee believes this compensation philosophy balances the need for competitiveness in attracting, engaging and retaining top talent while being measured and cost effective. This philosophy is also aligned with our executive compensation objective of linking pay to performance. When we benchmark and set compensation for our executives against a peer group, we focus on "target" compensation. Target compensation is the value of a pay opportunity as of the beginning of the year. For short-term incentives, this means the value of that incentive opportunity based on the target percentage of salary if our performance objectives are achieved. For example, our Parent's Chief Executive Officer's target annual incentive opportunity is 100% of salary. This means if we reach our targeted financial objectives for the year, a target incentive award would likely be paid. Correspondingly, if performance should fall short or rise above these goals, then the earned incentive award would typically be lesser or greater than targeted. In any event, target annual incentive opportunities are not a certainty but are a function of business results.

For the performance shares, the ultimate value of any earned award is entirely a function of performance against the pre-established 3-year performance goals as well as the value of the underlying stock price. Also, for the RSUs the value of any earned award is a function of continued service and the value of the underlying stock price. The target value is not a certainty but only the value of the opportunity.

What ultimately might be earned from either short- or long-term incentives is a function of performance and extended service. With respect to our variable pay programs, it is generally not the Company's purpose to deliver comparable pay outcomes versus that of other companies because outcomes can differ by company based on their performance. Rather, our general compensation objective is to deliver comparable pay opportunities. Realized results will then be a significant function of performance and continued service. This is a common convention among companies; nonetheless, it is an important context to consider when reviewing the remainder of this CD&A where regular references to target award opportunities and/or grant date values for our compensation programs appear.

Target total compensation opportunities are intended to approximate the 50th percentile of our Parent's peer group (as defined below) with flexibility to pay higher or lower amounts based on individual contribution, competition, retention, succession planning and the uniqueness and complexity of a position. To review overall compensation delivered, the Committee utilizes tally sheets that provide a summary of the elements of compensation for each senior executive. The tally sheets indicate compensation opportunities and actual pay earned.

The compensation opportunities vary significantly from individual to individual based on the specific nature of the executive position. For example, our Parent's Chief Executive Officer is responsible for the overall performance of Progress Energy and, as such, his position has a greater scope of responsibility than our other executive positions and is benchmarked accordingly. From a market perspective, the position of Chief Executive Officer receives a greater compensation opportunity than other executive positions. The Committee therefore sets our Parent's Chief Executive Officer's compensation opportunity at a level that reflects the responsibilities of his position and the Committee's expectations.

COMPETITIVE BENCHMARKING

On an annual basis, the Committee's compensation consultant provides the Committee with a written analysis comparing base salaries, target annual incentives and the grant date value of long-term incentives of our executive officers to compensation opportunities provided to executive officers of our Parent's peers. The comparative analysis is based on the 50th percentile (i.e., the median) values of the peer group. For 2011, the Committee approved the use of a peer group of 21 integrated utilities (the "Benchmarking Peer Group"). The Benchmarking Peer Group is comprised of utilities that have regulated and non-regulated business and was chosen based primarily on comparability of business, similarity in size, and likely competitors for talent. The 2010 median revenue of the Benchmarking Peer Group is $10.9 billion compared to our Parent's $10.2 billion. These companies would likely be companies with which we primarily compete for executive talent. The table below lists the companies in the Benchmarking Peer Group.

Benchmarking Peer Group		
Allegheny Energy, Inc.[1]	Duke Energy Corporation	PG&E Corporation
Ameren Corporation	Edison International	Pinnacle West Capital Corporation
American Electric Power Co., Inc.	Entergy Corporation	PPL Corporation
CenterPoint Energy, Inc.	Exelon Corporation	SCANA Corporation
CMS Energy Corporation	FirstEnergy Corporation	Southern Company
Dominion Resources, Inc.	NextEra Energy, Inc.	TECO Energy, Inc.
DTE Energy Company	NiSource, Inc.	Xcel Energy, Inc.

[1] Allegheny Energy, Inc. merged with FirstEnergy Corporation on February 25, 2011.

The electric utility industry has subsectors identified frequently as competitive merchant, regulated delivery, regulated integrated, and unregulated integrated (typically state-regulated delivery and unregulated generation). Each of these subsectors typically differs in financial performance and market valuation characteristics such as earnings multiples, earnings growth prospects and dividend yields. Progress Energy generally is identified as being in the regulated integrated subsector. The Committee annually evaluates the Benchmarking Peer Group to ensure that it remains appropriate for compensation comparisons.

SECTION 162(m) IMPACTS

Section 162(m) of the Internal Revenue Code of 1986, as amended, limits (with certain exceptions) the amount a publicly held company may deduct each year for compensation over $1 million paid or accrued with respect to its chief executive officer and any of the other three most highly compensated officers (excluding the chief financial officer). Certain performance-based compensation is, however, specifically exempt from the deduction limit. To qualify as performance-based, compensation must be paid pursuant to a plan that is:

- administered by a committee of outside directors;
- based on achieving objective performance goals; and
- disclosed to and approved by the shareholders.

The Committee considers the impact of Section 162(m) when designing executive compensation elements and attempts to minimize nondeductible compensation. The PSSP under the 2007 Equity Incentive Plan (the "Equity Incentive Plan") approved by our Parent's shareholders in 2007 is designed to meet the deductibility requirements of Section 162(m) as performance-based pay. Our Parent also received shareholder approval of the Progress Energy 2009 Executive Incentive Plan (the "EIP"), an annual cash incentive plan for our Parent's NEOs, in 2009. The MICP and EIP were designed to work together to enable the Company to preserve the tax deductibility of incentive awards under Section 162(m) of the Internal Revenue Code, as amended, to the extent practicable. The sole purpose of the EIP is to preserve the tax deductibility of incentive awards that are qualified performance-based compensation.

STOCK OWNERSHIP GUIDELINES

To align the interests of our executives with the interests of our Parent's shareholders, the Committee utilizes stock ownership guidelines for all executive officers. The guidelines are designed to ensure that our management maintains a significant financial stake in Progress Energy's long-term success. The guidelines require each senior executive to own a multiple of his or her base salary in the form of Progress Energy common stock within five years of assuming his or her position. The required levels of ownership are designed to reflect the level of responsibility that the executive positions entail and to be consistent with prevailing market practices.

The Committee benchmarked both the position levels and the multiples of our guidelines against those of the Benchmarking Peer Group and general industry practices. The benchmarking for 2011 indicated that our Parent's guidelines were "at market" with respect to ownership levels, the types of equity that count toward ownership, and the timeframe for compliance. The stock ownership guidelines for Progress Energy's executive officer positions are shown in the table below:

Position Level	Stock Ownership Guidelines
Chief Executive Officer	5.0 times Base Salary
Chief Operating Officer	4.0 times Base Salary
Chief Financial Officer	3.0 times Base Salary
Presidents/Executive Vice Presidents/Senior Vice Presidents	3.0 times Base Salary

For purposes of meeting the applicable guidelines, the following are considered as common stock owned by an executive: (i) shares owned outright by the executive; (ii) stock held in a defined contribution, Employee Stock Ownership Plan, or other stock-based plan; (iii) phantom stock deferred under an annual incentive or base salary deferral plan; (iv) stock earned and deferred in any long-term incentive plan account; (v) restricted stock awards and RSUs; and (vi) stock held in a family trust or immediate family holdings.

Directors and employees, including the NEOs, are not permitted to enter into hedging transactions involving our Parent's stock.

As of February 22, 2012, our NEOs exceeded the guidelines (see Management Ownership table on page 8 of this Proxy Statement for specific details).

II. ELEMENTS OF COMPENSATION

The table below summarizes the current elements of our Parent's executive compensation program.

Element	Brief Description	Primary Purpose	Short- or Long-Term Focus
Base Salary	Fixed compensation. Annual merit increases reward individual performance and growth in the position.	Basic element of compensation that pays for expertise and experience and is necessary to attract, engage and retain executives.	Short-term (annual)
Annual Incentive	Variable compensation based on achievement of annual performance goals.	Rewards operating performance results that are consistent with providing safe, reliable and efficient electric service.	Short-term (annual)
Long-Term Incentives — Performance Shares	Variable compensation based on achievement of long-term performance goals.	Align interests of shareholders and management and aid in attracting, engaging and retaining executives.	Long-term
Long-Term Incentives — Restricted Stock/ Restricted Stock Units	Variable compensation based on target levels. Service-based vesting.	Align interests of shareholders and management and essential in attracting, engaging and retaining executives.	Long-term
Supplemental Senior Executive Retirement Plan	Formula-based compensation, based on salary, annual incentives and eligible years of service.	Provides long-term retirement benefit influenced by service and performance. Aids in attracting, engaging and retaining executives.	Long-term
Management Change-In-Control Plan	Defines our Parent's and Company's relationship with executives in the event of a change-in-control.	Aligns interests of shareholders and management and aids in (i) attracting executives; (ii) engaging and retaining executives during transition following a change-in-control; and (iii) focusing executives on maximizing value for shareholders.	Long-term
Employment Agreements	Define our Parent's and Company's relationship with its executives and provide protection to each of the parties in the event of termination of employment.	Aid in attracting, engaging and retaining executives.	Long-term
Executive Perquisites	Personal benefits awarded outside of base pay and incentives.	Aid in attracting, engaging and retaining executives and allowing executives to focus their energies on Company priorities.	Short-term (annual)
Other Broad-Based Benefits	Employee benefits such as health and welfare benefits, 401(k) and pension plan.	Basic elements of compensation expected in the marketplace. Aid in attracting, engaging and retaining executives.	Both Short- and Long-term
Deferred Compensation	Provides executives with tax deferral options in addition to those available under our qualified plans.	Aids in attracting, engaging and retaining executives.	Long-term

The table below shows the target awards of short-term and long-term incentives to each NEO for 2011. Target opportunities for incentives are expressed as a percentage of base salary. Additional elements of compensation are discussed further in this section.

Named Executive Officer	Base Salary (as of 1/1/12)	Short-Term (annual) Incentive Target[1]	Long-Term Incentive Targets		Total Incentive Target
			Performance Shares[2]	Restricted Stock Units	
William D. Johnson	$1,030,000	100%	233%	117%	450%
Mark F. Mulhern	$495,945	55%	117%	58%	230%
Jeffrey J. Lyash	$466,590	55%	117%	58%	230%
Lloyd M. Yates	$461,440	55%	117%	58%	230%
John R. McArthur	$502,640	55%	117%	58%	230%

[1] Annual incentive awards can range from 0%-200% of target percentages.

[2] Payout opportunities can range from 0%-200% of target percentages.

1. BASE SALARY

The primary purpose of base salaries is to provide a basic element of compensation necessary to attract and retain executives. Base salary levels are established based on data from the Benchmarking Peer Group and in consideration of each executive officer's skills, experience, responsibilities and performance. Market compensation levels that approximate the 50th percentile of the Benchmarking Peer Group are used to assist in establishing each executive's job value (commonly called the "midpoint" at other companies). These job values serve as the market reference for determining base salaries.

Each year, the compensation consultant provides the market values for our executive officer positions. Based, in part, on these market values and, in part, on the executives' achievement of individual and Company goals, our Parent's Chief Executive Officer then recommends to the Committee base salary adjustments for our executive officers (excluding himself). The Committee reviews the proposed base salaries and adjusts them as it deems appropriate based on the executives' achievement of individual and Company goals and market trends that result in changes to job values. The Committee approves them in the first quarter of each year. The Committee meets in executive session with the compensation consultant to review and establish our Parent's Chief Executive Officer's base salary.

2. ANNUAL INCENTIVE

The MICP is an annual cash incentive plan in which our executives, managers and supervisors participate. The Company includes managers and supervisors in the MICP to increase accountability for all levels of the Company's management team and to better align compensation with management performance. Annual incentive opportunities are provided to executive officers to promote the achievement of annual performance objectives. MICP targets are based on a percentage of each executive's base salary and are intended to offer target award opportunities that approximate the 50th percentile of the market for the Benchmarking Peer Group.

Each year, the Committee establishes, based on the recommendations of our Parent's Chief Executive Officer, the threshold, target and outstanding levels for the performance measures applicable to the NEOs. The 2011 MICP performance measures were ongoing earnings per share ("Ongoing EPS") and legal entity net income for the Company and PEF as shown in the table below:

2011 MICP Financial Performance Goals			
(in millions except Ongoing EPS)	**Threshold**	**Target**	**Outstanding**
Progress Energy Ongoing EPS	$2.90	$3.10	$3.20
Company Net Income	$568	$600	$616
PEF Net Income	$467	$493	$506

The MICP's performance targets are designed to align with our financial plan and are intended to appropriately motivate the executive officers to achieve the desired corporate financial objectives by focusing on legal entity net income results. The potential MICP funding for each performance measure is 50% at threshold, 100% at target and 200% at outstanding (maximum). Interpolation is applied when actual performance is between the identified levels. Each performance measure is assigned a weight based on the relative importance of that measure to Progress Energy's performance. During the year, updates are provided to the Committee on Progress Energy's performance as compared to the performance measures. For 2011, the NEOs' performance measures under the MICP were weighted among Ongoing EPS and legal entity net income as follows:

		Performance Measures (Relative Percentage Weight)		
Named Executive Officer	**Target Opportunity**	**Progress Energy, Inc. Ongoing EPS**	**Company Net Income**	**PEF Net Income**
William D. Johnson	100%	100%	—	—
Mark F. Mulhern	55%	100%	—	—
Jeffrey J. Lyash	55%	35%	32.5%	32.5%
Lloyd M. Yates	55%	45%	55%	—
John R. McArthur	55%	100%	—	—

The determination of the annual MICP award that each NEO receives has two steps: i) funding the MICP awards based on the performance as compared to the financial goals specified above; and ii) determining individual MICP awards.

First, the Committee approves the total amount that will be made available to fund MICP awards to managers and executives, including the NEOs. To determine the total amount available to fund all MICP awards, our Parent calculates an amount for each MICP participant by multiplying each participant's base salary by a performance factor (based on the sum of a participant's weighted target award achievements). The performance factor ranges between 0 and 200% of a participant's target award, depending upon the results of each applicable performance measure. The sum of these amounts for all participants is the total amount of funds available to pay to all participants, including the NEOs.

Second, our Parent's Chief Executive Officer recommends to the Committee an MICP award payment for executives (excluding himself) based on the executive's target award opportunity, the degree to which Progress Energy achieved certain goals, and the executive's individual performance based on achieving individual goals and operating results. The Committee reviews our Parent's Chief Executive Officer's recommendations and approves and/or makes adjustments as appropriate. Our Parent's Chief Executive Officer's MICP award payment is determined by the Committee based upon the Committee's annual evaluation of his performance. The Committee may reduce but cannot increase the amount payable to a participant according to business factors determined by the Committee, including the performance measures under the MICP.

As allowed by the MICP, the Committee uses discretion to adjust funding amounts up or down depending on factors that it deems appropriate, such as weather, storm costs, impairments, restructuring costs, and gains/losses on sales of assets. The Committee uses Ongoing EPS as defined and reported by Progress Energy in its annual earnings release. See the reconciliation of Ongoing EPS to GAAP EPS attributable to controlling interests under the caption "Results of Operations" in Item 7 of our Parent's Form 10-K for the year ended December 31, 2011, filed on February 29, 2012.

Based on management's recommendations, with respect to 2011, the Committee exercised discretion for the three performance measures: our Parent's Ongoing EPS, Company net income, and PEF net income. The Committee approved adjusting Progress Energy's Ongoing EPS results upward by a net $0.11 to account for favorable weather, storm costs, regulatory costs and discretionary spending. The Committee approved adjusting the Company's net income for favorable weather, storm costs, regulatory costs and discretionary spending for a net upward adjustment of $35 million. The Committee approved adjusting PEF's net income for favorable weather, tax expense and the results of a litigation settlement for a net downward adjustment of $26 million.

3. LONG-TERM INCENTIVES

The Equity Incentive Plan allows the Committee to make various types of long-term incentive awards to Equity Incentive Plan participants, including the NEOs. The awards are provided to the NEOs to align the interests of each executive with those of our Parent's shareholders. Long-term incentive awards are intended to offer target award opportunities that approximate the 50th percentile of the Benchmarking Peer Group. Currently, the Committee utilizes two types of equity-based incentives: RSUs and performance shares.

The Committee has determined that to accomplish our compensation program's purposes effectively, equity-based awards should consist of one-third RSUs and two-thirds performance shares. This allocation reflects the Committee's strategy of utilizing long-term incentives to retain officers, align officers' interests with those of our and our Parent's shareholders and drive specific financial performance.

Performance shares are intended to focus executive officers on the multi-year sustained achievement of financial and shareholder value objectives. RSUs are intended to further align executives' interests with shareholder interests while providing strong retention for the executive to remain with the Company long enough for the RSUs to vest.

See the table on page 21 for the 2011 long-term incentive targets for the NEOs.

After October 2004, Progress Energy ceased granting stock options. All previously granted stock options remain valid in accordance with their terms and conditions.

Performance Shares

The PSSP under the Equity Incentive Plan authorizes the Committee to issue performance shares to executives as selected by the Committee in its sole discretion. The value of a performance share is equal to the value of a share of Progress Energy's common stock, and earned performance share awards are paid in Progress Energy common stock. The performance period for a performance share is the three-consecutive-calendar-year period beginning in the year in which it is granted. Dividends or dividend equivalents are not paid on unvested performance shares. Rather, dividend equivalents accrue quarterly and are reinvested in additional shares that are only paid on earned performance shares at the end of each three-year performance cycle.

To determine the number of performance shares granted at the beginning of each performance cycle, our Parent divides the target award value by the closing stock price on the last trading day of the year prior to the beginning of the performance period. The performance shares must then be earned over the three-year performance cycle. The granting of performance shares does not provide the participant with any guarantee of actually receiving the awards.

Notwithstanding the above calculation, the Committee may exercise discretion in determining the size of each performance share grant, with the maximum grant size at 125% of target. In 2011, the Committee did not exercise this discretion with respect to any grant to the NEOs.

2007 Performance Share Sub-Plan (the "2007 PSSP")

The 2007 PSSP provides for an adjusted measure of total shareholder return (referred to as "Total Business Return" or TBR) to be utilized as the sole measure for determining the amount of a performance share award upon vesting. TBR is computed assuming a constant price to earnings ratio, which was set at the beginning of each performance period. During a period when our Parent was undergoing transformation of its underlying operating portfolio, this measure was intended to filter out external or market-based variations in Progress Energy's stock price and focus on internal restructuring. The performance measure also uses Progress Energy's publicly reported Ongoing EPS as the earnings component for determining performance share awards. The Committee chose this method as the sole performance measure to support its desire to better align the long-term incentives with the interests of our and our Parent's shareholders and to emphasize our focus on dividend and Ongoing EPS growth. TBR was used for the 2007 – 2009 and 2008 – 2010 performance share grants made under the 2007 PSSP. The performance measures for the 2008 – 2010 performance cycle are shown in the table below.

	Threshold	Target	Outstanding
2008 Total Business Return[1]	5%	8%	≥11%
2008 Percentage of Target Award Earned	25%	100%	200%

[1] Total shareholder return, adjusted to reflect a constant price to earnings ratio set at January 1 of the grant year and to reflect Progress Energy's Ongoing EPS for each year of the performance period.

Additionally, the Committee retained the discretion to reduce the number of performance shares awarded if it determines that the payouts resulting from the TBR do not appropriately reflect the Company's actual performance.

In the first quarter of 2011, the Committee approved a payout of 100% of the target value for the 2008 – 2010 PSSP grants.

2009 Performance Share Sub-Plan (the "2009 PSSP")

The 2009 PSSP uses two equally weighted performance measures: relative total shareholder return (TSR) and earnings growth. TSR, unlike the previously discussed TBR, is based on the conventional metric of annual share price appreciation and dividends. By using a combination of relative TSR and ongoing earnings growth, the 2009 PSSP allows the Committee to consider Progress Energy's performance as compared to the PSSP Peer Group (as defined below), and management's achievement of internal goals.

Relative TSR

The relative TSR performance is calculated using Progress Energy's three-year annualized TSR ranked against the PSSP Peer Group. TSR is defined as the appreciation or depreciation in the value of the stock, plus dividends paid during the year, divided by the closing value of the stock on the last trading day of the preceding year. A 30-day opening/closing average stock value is used in determining the results to moderate the impact of wide swings in the stock value. The table below shows the percent of target awards that may be earned based on Progress Energy's relative TSR percentile ranking:

Performance and Award Structure (50%)	
Percentile Ranking	**Percent of Target Award Earned**
80^{th}	200%
50^{th}	100%
40^{th}	50%
$<40^{th}$	0%

However, regardless of the relative ranking, if Progress Energy's TSR is negative for the performance period, no award above the threshold can be earned.

In making awards under the 2009 PSSP, the Committee used a group of highly regulated utilities with a business strategy similar to our Parent's based on a percentage of regulated earnings (the "PSSP Peer Group"). These companies have a significant amount of their earnings generated from regulated assets. In addition, the PSSP Peer Group was selected based on other factors including revenues, market capitalization, and enterprise value. The PSSP Peer Group differs from the Benchmarking Peer Group the Committee uses for purposes of benchmarking compensation. The Benchmarking Peer Group is a broader group that represents those companies with which we primarily compete for executive talent and includes companies that are not regulated integrated utilities. The Committee believes that for purposes of our long-term incentive plan, it is more appropriate to use the PSSP Peer Group comprised of companies that derive a significant percentage of their earnings from regulated businesses. The table below lists the companies in the PSSP Peer Group.

PSSP Peer Group		
Alliant Energy Corporation	NV Energy, Inc.	Southern Company
American Electric Power, Inc.	PG&E Corporation	Westar Energy, Inc.
Consolidated Edison, Inc.	Pinnacle West Capital Corporation	Wisconsin Energy Corp.
Duke Energy Corporation	Portland General Electric Company	Xcel Energy, Inc.
Great Plains Energy, Inc.	SCANA Corporation	

Earnings Growth

Earnings growth is based on Progress Energy's annual Ongoing EPS. Ongoing EPS is determined in accordance with our Parent's "Policy for Disclosure of Non-GAAP Measures." See the reconciliation of Ongoing EPS to GAAP EPS attributable to controlling interests under the caption "Results of Operations" in Item 7 of our Parent's Form 10-K for the year ended December 31, 2011, filed on February 29, 2012. The earnings growth component of the PSSP award is based on Progress Energy's earnings growth performance as measured against pre-established goals set at the beginning of the performance period. The Committee determined the earnings growth targets for the 2011 annual grant were appropriate in consideration of consistency with analysts' expectations and the 2011 projected analysts' consensus on earnings growth for the PSSP Peer Group. The table below shows the percent of target awards that may be earned based on Progress Energy's earnings growth performance:

	Performance and Award Structure (50%)			
Performance	**Three-Year Average Ongoing EPS Growth**			**Percent of Target Award Earned**
	2009-2011	2010-2012	2011-2013	
Threshold	2%	1%	1%	50%
Target	4%	3%	2%	100%
Maximum	6%	5%	5%	200%

Restricted Stock Units

The RSU component of the current long-term incentive program helps us retain executives and aligns the interests of management with those of our Parent's shareholders and management by rewarding executives for increasing and sustaining shareholder value. The Committee believes that the service-based nature of RSUs is essential in retaining an experienced and capable management team and is a common market practice.

Executive officers typically receive a grant of service-based RSUs in the first quarter of each year, which is subject to a three-year graded vesting schedule. The size of each grant is based on the executive officer's target award opportunity and is determined by using the closing stock price of our Parent's common stock on the last trading day of the year prior to the date of the award. The Committee establishes target levels based on the peer group information discussed under the caption "Competitive Positioning Philosophy" on page 17 above. The 2011 RSU targets for the NEOs are shown in the table on page 21 above. The granting of RSUs does not provide the participant with any guarantee of actually receiving the awards. Holders of RSUs receive quarterly cash dividend equivalents equal to the amount of any quarterly dividends paid on our Parent's common stock.

To further accent the retention quality of the Equity Incentive Plan and to recognize the contribution of the officer team, including the NEOs, the Committee may also issue in its discretion service-based ad hoc grants of RSUs to executives. Ad hoc grants were awarded by the Committee during 2011 to each of our NEOs as described under the caption "2011 Compensation Decisions" on page 33 below.

4. SUPPLEMENTAL SENIOR EXECUTIVE RETIREMENT PLAN

The Supplemental Senior Executive Retirement Plan ("SERP") sponsored by Progress Energy provides a supplemental, unfunded pension benefit for executive officers who have at least 10 years of service with at least three years of service on our Senior Management Committee ("SMC"), i.e., service as a Senior Vice President or above. The SERP is designed to provide pension benefits above those earned under our qualified pension plan. Current tax laws place various limits on the benefits payable under our qualified pension plan, including a limit on the amount of annual compensation that can be taken into account when applying the plan's benefit formulas. Therefore, the retirement incomes provided to the NEOs by the qualified plans generally constitute a smaller percentage of final pay than is typically the case for other Company employees. To make up for this shortfall and to maintain the market-competitiveness of our Parent's executive retirement benefits, we maintain the SERP for members of the SMC, including the NEOs.

The SERP defines covered compensation as annual base salary plus the annual cash incentive award. The qualified plans define covered compensation as base salary only. The Committee believes it is appropriate to include annual cash incentive awards in the definition of covered compensation for purposes of determining pension plan benefits for the NEOs to ensure that the NEOs can replace in retirement a portion of total compensation received during employment. This approach takes into account the fact that base pay alone comprises a relatively smaller percentage of a NEOs' total compensation than of other Company employees' total compensation.

The Committee believes that the SERP is a valuable and effective tool for attraction and retention due to its significant benefit and vesting requirements. It is also a common tool among the Benchmarking Peer Group and utilities in general. Total years of service attributable to an eligible executive officer may consist of actual or deemed years. The Committee grants deemed years of service on a case-by-case basis depending upon our need to attract and retain a particular executive officer. All of our NEOs participate in the SERP and are fully vested in the SERP.

Payments under the SERP are made in the form of an annuity, payable at age 65. The monthly SERP payment is calculated using a formula that equates to 4% per year of service (capped at 62%) multiplied by the average monthly eligible pay for the highest completed 36 months of eligible pay within the preceding 120-month period. Eligible pay includes base salary and annual incentive. (For those executives who became SERP participants on or after January 1, 2009, other than executives who were members of SMC on December 31, 2008, the target benefit percentage is 2.25% rather than 4% per year of service. None of the NEOs for 2011 are subject to the new benefit percentage.) Benefits under the SERP are fully offset by Social Security benefits and by benefits paid under our Parent's qualified pension plan. An executive officer who is age 55 or older with at least 15 years of service may elect to retire and commence his or her SERP benefit prior to age 65. The early retirement benefit will be reduced by 2.5% for each year the participant receives the benefit prior to reaching age 65.

On March 16, 2011, the Board amended the SERP in two respects. The SERP was amended to provide that all service with Progress Energy and its affiliates, including Duke Energy and its affiliates, after completion of the merger will be treated as service as a Senior Vice President or above for purposes of meeting the SERP's eligibility requirements. Second, the SERP was amended to limit participation in the SERP to executives who were members of the SMC on January 8, 2011. On March 14, 2012, the SERP was further amended to clarify that for all members of our Parent's SMC on December 31, 2008, the target benefit percentage is 4%.

5. MANAGEMENT CHANGE-IN-CONTROL PLAN

Our Parent sponsors a Management Change-In-Control Plan (the "CIC Plan") for selected employees. The purpose of the CIC Plan is to:

- retain key management employees who are critical to the negotiation and subsequent success of any transition resulting from a change-in-control ("CIC") of our Parent;
- focus executives on maximizing shareholder value;
- ensure business continuity during a transition and thereby maintain the value of the acquired company;
- allow executives to focus on their jobs and not alternative future employment if they should be terminated; and
- retain key executives during a period of potentially protracted transition for the benefit of our and our Parent's shareholders and customers.

Providing such protection to executive officers in general minimizes disruption during a pending or anticipated CIC. Under our CIC Plan, our Parent generally defines a CIC as occurring at the earliest of the following:

- the date any person or group becomes the beneficial owner of 25% or more of the combined voting power of our Parent's then outstanding securities; or
- the date a tender offer for the ownership of more than 50% of our Parent's then outstanding voting securities is consummated; or

- the date our Parent consummates a merger, share exchange or consolidation with any other corporation or entity, regardless of whether our Parent is the surviving company, unless our Parent's outstanding securities immediately prior to the transaction continue to represent more than 60% of the combined voting power of the outstanding voting securities of the surviving entity immediately after the transaction; or

- the date, when, as a result of a tender offer, exchange offer, proxy contest, merger, share exchange, consolidation, sale of assets or any combination of the foregoing, the directors serving as of the effective date of the change-in-control plan, or elected thereafter with the support of not less than 75% of those directors, cease to constitute at least two-thirds (⅔) of the members of Progress Energy's Board of Directors; or

- the date when our Parent's shareholders approve a plan of complete liquidation or winding-up or an agreement for the sale or disposition by us of all or substantially all of our assets; or

- the date of any other event that Progress Energy's Board of Directors determines should constitute a CIC.

The Committee has the sole authority and discretion to designate employees and/or positions for participation in the CIC Plan. Consistent with the level of responsibility inherent in their roles and consistent with market practice, the Committee has designated certain positions, including all of the NEO positions, for participation in the CIC Plan. The benefits provided under the CIC Plan do not duplicate the employment agreement severance benefits in the case of CIC Plan participants. Participants are not eligible to receive any of the CIC Plan's benefits absent both a CIC of our Parent and an involuntary termination of the participant's employment without cause, including voluntary termination for good reason. Good reason termination includes changes in employment circumstances such as a:

- reduction of base salary or material reduction of incentive compensation opportunity;

- material adverse change in position or scope of authority;

- significant change in work location; or

- breach of provisions of the CIC Plan.

Rather than allowing benefit amounts to be determined at the discretion of the Committee, the CIC Plan has specified multipliers designed to be competitive with current market practices. With the assistance of its compensation consultant, the Committee has reviewed the design of the CIC Plan to ensure that it meets our Parent's business objectives and falls within competitive parameters. The Committee has determined that the current CIC Plan is effective at meeting the goals described above.

The CIC Plan provides separate tiers of severance benefits based on the position a participant holds within our Parent. The continuation of health and welfare benefits coverage and the degree of excise tax gross-up for terminated participants align with the length of time during which they will receive severance benefits.

The following table sets forth the key provisions of the CIC Plan benefits as it relates to our NEOs:

	Tier I	Tier II
Eligible Positions	Chief Executive Officer, Chief Operating Officer, Presidents and Executive Vice Presidents	Senior Vice Presidents
Cash Severance	300% of base salary and annual incentive[1]	200% of base salary and annual incentive[1]
Health & Welfare Coverage Period	Coverage up to 36 months	Coverage up to 24 months
Gross-ups	Full gross-up of excise tax	Conditional gross-up of excise tax

[1] The cash severance payment will be equal to the sum of the applicable percentage of annual base salary and the greater of the average of the participant's annual incentive award for the three years immediately preceding the participant's employment termination date, or the participant's target annual incentive award for the year the participant's employment with the Company terminates.

Additionally, the CIC Plan has the following key provisions:

Benefit	Description
Annual Incentive	100% of target incentive if terminated within coverage period after CIC.
Restricted Stock Agreements	Restrictions are fully waived on all outstanding grants if terminated during coverage period (unless outstanding awards are not assumed by the acquiring company in which case they would vest at CIC).
Performance Share Sub-Plan	Outstanding awards vest (at the target level) as of the termination date (unless outstanding awards are not assumed by the acquiring company in which case they would vest at CIC).
Supplemental Senior Executive Retirement Plan	Participant shall be deemed to have met minimum service requirements for benefit purposes, and participant shall be entitled to payment of benefit under the SERP.
Deferred Compensation	Entitled to payment of accrued benefits in all accrued nonqualified deferred compensation plans.

The CIC Plan also permits the Progress Energy Board to establish a nonqualified trust to protect the benefits of the impacted participants. This type of trust generally is established and funded to protect nonqualified and/or deferred compensation against various risks such as a CIC or a management change-of-heart. Any such trust the Board establishes would be irrevocable and inaccessible to future or current management. In July, 2011, the CIC Plan was amended to eliminate the Progress Energy Board's right to establish such a trust in the event of a merger with Duke Energy.

Application of the CIC Plan and Other Compensation Related Consequences of the Proposed Merger with Duke Energy

On January 8, 2011, Duke Energy and Progress Energy entered into an Agreement and Plan of Merger (the "Merger Agreement"). Pursuant to the Merger Agreement, if the merger is consummated, our Parent will become a wholly owned subsidiary of Duke Energy and shareholders of our Parent will receive shares of Duke Energy common stock. Consummation of the merger is subject to customary conditions, including among other things, regulatory approval. The shareholders of Duke Energy and Progress Energy approved the proposed merger in August, 2011.

Our NEOs will not receive additional compensation or benefits under their employment agreements or the CIC Plan solely on account of the consummation of the merger with Duke Energy. However, subject to the limitations described below, if an NEO is terminated without "cause" or resigns with "good reason" within twenty-four months after consummation of the merger, they will be entitled to severance benefits under the CIC Plan as set forth in the "Involuntary or Good Reason Termination (CIC)" column of the tables captioned "Potential Payments Upon Termination," on pages 50 through 59 below. The eligibility of certain NEOs to receive the CIC Plan benefits is limited by the following:

- Each of our NEOs are expected to assume new positions with Duke Energy effective upon consummation of the merger. Thus, we do not expect that these executives' employment will be terminated in connection with consummation of the merger.

- In connection with the execution of the Merger Agreement, Duke Energy and Mr. Johnson executed a term sheet pursuant to which the parties agreed to enter into an employment agreement upon consummation of the merger. Pursuant to the term sheet, Mr. Johnson has waived his right to resign with "good reason," and receive CIC Plan benefits or to assert a "constructive termination" under his existing employment agreement, on account of (i) his required relocation to Charlotte, North Carolina, (ii) any changes to his positions, duties and responsibilities in connection with his acceptance of the new position with Duke Energy, or (iii) any changes to his total incentive compensation opportunity following the merger with Duke Energy. In addition, Mr. Johnson's term sheet specifies that if he is involuntarily terminated without "cause" or resigns for "good reason" on or prior to the second anniversary of the completion of the merger, he will not receive a tax gross-up for the parachute payment excise tax under Sections 280G and 4999 of the Internal Revenue Code. In addition to the waivers described above, Mr. Johnson's term sheet also specifies that if he is involuntarily terminated without "cause" or resigns for "good reason" following the second anniversary of, but prior to the third anniversary of, the consummation of the merger, he will be entitled to the severance benefits provided under his current employment agreement. If the merger with Duke Energy is not completed, the waivers described in this paragraph will not take effect.

- Also in connection with the execution of the Merger Agreement, each of Messrs. Yates, Lyash, McArthur and Mulhern entered into a letter agreement with Progress Energy waiving certain rights of such executive officer under the CIC Plan and such executive officer's employment agreement. Messrs. Yates, Lyash, McArthur and Mulhern have each waived the right to resign with "good reason," and receive the CIC Plan benefits or to assert a "constructive termination" under his employment agreement, on account of (i) a required relocation to Charlotte, North Carolina, (ii) a change in his position, duties or responsibilities in connection with his acceptance of the new position with Duke Energy or (iii) a reduction in his total incentive compensation opportunity by virtue of his participation in Duke Energy's incentive compensation plans (provided that his target incentive compensation opportunity is substantially similar to that of similarly situated Duke Energy executives). Thus, Messrs. Yates, Lyash, McArthur and Mulhern cannot claim entitlement to CIC Plan benefits or severance under their employment agreements upon a resignation following the merger for any of these reasons. The letter agreements will be terminated in the event that the Merger Agreement is terminated prior to the merger with Duke Energy being consummated.

Upon consummation of the merger, outstanding options to purchase shares of our Parent's common stock and outstanding awards of restricted stock, RSUs, phantom shares and performance shares will be converted into equity or equity-based awards in respect of a number of shares of Duke Energy common stock equal to the number of shares of Progress Energy common stock represented by such award multiplied by the exchange ratio under the Merger Agreement and will remain subject to the same vesting requirements as were applicable to such awards prior to consummation of the merger with Duke Energy. In other words, the vesting of options and other equity awards held by our NEOs will not be accelerated on account of the completion of the merger. The outstanding annual incentive awards of our NEOs also will remain subject to their original vesting requirements and will remain subject to performance criteria. The compensation committee of the Duke Energy board of directors will adjust the original performance criteria for outstanding performance shares and annual incentive awards as it determines is appropriate and equitable to reflect the merger, Progress Energy's performance prior to completion of the merger and the performance criteria of awards made to similarly situated Duke Energy employees.

Notwithstanding the provisions of the CIC Plan, the SERP, the MICP, the PSSP, and the Management Deferral Compensation Plan (the "MDCP") providing for the funding of a nonqualified trust to protect the benefits of the impacted participants, the terms of the Merger Agreement prohibit the funding of any such trust and stipulate that all applicable plans must be amended prior to the consummation of the merger to eliminate any funding requirement. Each of these plans was amended on July 12, 2011, to eliminate any requirement to establish or fund a nonqualified trust in connection with a merger with Duke Energy.

6. EMPLOYMENT AGREEMENTS

Each NEO has an employment agreement that documents the Company's and our Parent's relationship with that executive. We provide these agreements to the executives as a means of attracting and retaining them. Each agreement has a term of three years. When an agreement's remaining term diminishes to two years, the agreement automatically adds another year to the term, unless we give a 60-day advance notice that we do not want to extend the agreement. If an NEO is terminated without cause during the term of the agreement, he is entitled to severance payments equal to his base salary times 2.99, as well as up to 18 months of COBRA reimbursement. A description of each NEOs' employment agreement is discussed under the "Employment Agreement" section of the "Discussion of Summary Compensation Table and Grants of Plan-Based Awards Table" on page 41 of this Proxy Statement.

In anticipation of the closing of the proposed merger with Duke Energy and the transition to Duke Energy's employment practices for executives, in October, 2011, the Company notified its NEOs that it would not renew their employment agreements upon expiration of the current terms.

7. EXECUTIVE PERQUISITES

We provide limited perquisites and other benefits to our executives. Amounts attributable to perquisites are disclosed in the "All Other Compensation" column of the Summary Compensation Table on page 37.

The Committee has determined that the current perquisites are appropriate and consistent with market practices. The perquisites available to the NEOs during 2011 include:

Perquisites for 2011	Description
Personal Travel on Corporate Aircraft and "Business-Related" Spousal Travel[1]	Personal and spousal travel on corporate aircraft is permitted under very limited circumstances.
Financial and Estate Planning	An annual allowance of up to $16,500 for the purpose of purchasing financial and estate planning counseling and services and preparation of personal tax return.
Luncheon and Health Club Dues	Membership in an approved luncheon club and membership in a health club of executive officer's choice.
Executive Physical	Reimbursement of up to $2,500 for an extensive physical at a clinic specializing in executive physicals, every other year.
Internet and Telecom Service[2]	Monthly fees for Internet and telecom access.
Home Security	An installed home security system and payment of monitoring fees.
Accidental Death and Dismemberment Insurance	$500,000 of AD&D insurance for each executive officer.

[1] Personal travel on Progress Energy's aircraft in the event of a family emergency or similar situation is permitted with the approval of Progress Energy's Chief Executive Officer. Executives' spouses may also travel on Progress Energy's aircraft to accompany the executives to "business-related" events that executives' spouses are requested to attend. For 2011, the NEOs whose perquisites included spousal travel on corporate aircraft for business purposes were Messrs. Johnson, Lyash and Yates.

[2] Including home use of Company-owned computer.

The Committee believes that the perquisites we provide to our executives are reasonable, competitive and consistent with our overall executive compensation program in that they help us attract and retain skilled and qualified executives. We believe that these benefits generally allow our executives to work more efficiently and, in the case of the tax and financial planning services, help them to optimize the value received from all of the compensation and benefits programs offered. The costs of these benefits constitute only a small percentage of each NEOs' total compensation.

8. OTHER BROAD-BASED BENEFITS

The NEOs receive our general corporate benefits provided to all of our regular, full-time, nonbargaining employees. These broad-based benefits include the following:

- participation in the Progress Energy 401(k) Plan (including a limited match by our Parent of up to 6% of eligible compensation);
- participation in Progress Energy's funded, tax-qualified, noncontributory defined-benefit pension plan, which uses a cash balance formula to accrue benefits; and
- general health and welfare benefits such as medical, dental, vision and life insurance, as well as long-term disability coverage.

9. DEFERRED COMPENSATION

Progress Energy sponsors the MDCP, an unfunded, deferred compensation arrangement. The plan is designed to provide executives with tax deferral options, in addition to those available under the existing qualified plans. An executive may elect to defer, on a pre-tax basis, payment of up to 50% of his or her salary for a minimum of five years or until his or her date of retirement. As a make-up for the 401(k) statutory compensation limits, executives receive deferred compensation credits of 6% of their base salary over the Internal Revenue Code statutory compensation limit on 401(k) retirement plans. The Committee views the matching feature as a restoration benefit designed to restore the matching contribution the executive would have received under the 401(k) retirement plan in the absence of the Internal Revenue Service compensation limits. Each executive may allocate his or her deferred compensation among available deemed investment funds that mirror those options available under the Progress Energy 401(k) plan. Executives may elect to receive distributions, either in a lump sum or installments of 2 to 10 years, on (1) the April 1 following the date that is 5 years from the last day of the plan year in which the deferral was made; or (2) upon separation from employment.

Executives can elect to defer up to 100% of their MICP and/or performance share awards. The deferral option is provided as an additional benefit to executive officers to provide flexibility in the receipt of compensation. Deferred awards may be allocated among deemed investment options that mirror the Progress Energy 401(k) Plan. Effective September 1, 2010, the NEOs cannot allocate deferred awards to the deemed Progress Energy stock investment fund. In anticipation of the merger with Duke Energy, the MICP was amended to eliminate the deferral option for awards earned in 2012. Executives may elect to receive distributions any date that is 5 years subsequent to when the award would otherwise be payable or any date that is within 2 years of the executive's retirement date. Executives will receive a distribution upon separation of employment other than by reason of death or retirement.

III. 2011 COMPENSATION DECISIONS

Chief Executive Officer Compensation

Lloyd M. Yates

In March 2011, Mr. Johnson recommended the Committee approve a merit-based adjustment to Mr. Yates' base salary supported by market data prepared by the Committee's independent compensation consultant. The Committee approved a base salary of $461,440, representing a 3% merit increase to his previous salary of $448,000. For 2011, Mr. Yates' MICP target award was set at 55% of base salary. The payout of the 2011 MICP award was based on the extent to which Mr. Yates achieved his performance goals, which were focused on the following general areas for our Parent's success:

- Excelling in the fundamentals of safety, operational excellence and customer satisfaction;
- Managing revenue, expenses and capital to achieve financial objectives;
- Promoting public, regulatory and political support; and
- Ensuring effective regulatory compliance.

In recognition of his accomplishments in 2011, and on Mr. Johnson's recommendation, the Committee awarded Mr. Yates an MICP award of $220,000, which is equal to 87% of Mr. Yates' target award opportunity. The Committee considered, among other things, Mr. Yates' significant role in managing the Company's operations and maintenance ("O&M") expenses that were impacted by higher nuclear maintenance costs to improve the Robinson Nuclear Plant performance and by storm restoration costs; successfully completing the Company's first audit of the North American Electric Reliability Corporation's cyber security standards by the SERC Reliability Corporation; and completing the new combined cycle plant at the Sherwood H. Smith, Jr. Energy Complex on time and under budget.

With respect to his long-term incentive compensation in 2011, Mr. Yates was granted 5,976 RSUs and 12,055 performance shares in accordance with his pre-established targets of 58% and 117%, respectively, of base salary. The performance shares are earned based on performance over the three years ending December 31, 2013. Additionally, 9,663 shares of the 2008 annual grant vested in 2011 and were paid out at 100% of target. On Mr. Johnson's recommendation, the Committee also awarded Mr. Yates an ad hoc grant of 4,000 RSUs that vest in 2014. The purpose of this grant was to address shortfalls in compensation compared to the Company's Benchmarking Peer Group and to provide a retention incentive for the pending merger with Duke Energy. Mr. Yates' total compensation as shown in the "Summary Compensation Table" on page 37 of this Proxy Statement increased 35.6% from the amount of total compensation he received in 2010, largely due to an increase in his accrued pension benefits.

Chief Financial Officer Compensation

Mark F. Mulhern

In March 2011, Mr. Johnson recommended the Committee approve a merit and market-based adjustment to Mr. Mulhern's base salary supported by market data prepared by the Committee's independent compensation consultant. The Committee approved a base salary of $495,945 for Mr. Mulhern, representing a 3% merit increase and 7.2% market-based adjustment increase to his previous salary of $450,000. The new base salary was set at 9% below the 50th percentile of the Benchmarking Peer Group. Mr. Mulhern's base salary was established at this level to more closely align with the market. It is the Committee's intention to increase Mr. Mulhern's salary over time to a level that is at the 50th percentile of the Benchmarking Peer Group.

For 2011, Mr. Mulhern's MICP target award was set at 55% of his base salary. This target award is the same target Mr. Mulhern had in 2009 after he assumed the Chief Financial Officer position and represents a target award opportunity that is below the 50th percentile of the market. Mr. Mulhern's performance goals for 2011 focused on the following general areas for our Parent's success:

- Achieving financial objectives;
- Integrating long-range planning and targeted nuclear project management improvement support;
- Continuing focus on capital discipline and timely identification of risk areas; and
- Achieving effective integration planning and required approvals for the proposed merger of our Parent with Duke Energy to position the combined company for success.

In recognition of the achievements he accomplished in 2011 and on Mr. Johnson's recommendation, the Committee awarded Mr. Mulhern an MICP award of $250,000, which is equal to 94% of Mr. Mulhern's target award. The Committee considered, among other things, Mr. Mulhern's significant role in our Parent's achievement of a 36% total shareholder return representing a first place ranking position in our Parent's Benchmarking Peer Group; the execution of a tender offer to repurchase our Parent's outstanding contingent value obligations issued in 2000; developing common baseline numbers to provide a foundation for tracking synergies associated with the proposed merger with Duke Energy; and negotiating a sublease of a building utilized by our Parent as one of its headquarters facilities that will mitigate a substantial liability after the proposed merger with Duke Energy.

With respect to his long-term incentive compensation, in 2011, Mr. Mulhern was granted 6,003 RSUs and 12,109 performance shares in accordance with his pre-established targets of 58% and 117%, respectively, of base salary. The performance shares are earned based on performance over the three years ending December 31, 2013. Additionally, 6,814 shares of the 2008 annual grant vested in 2011 and were paid out at 100% of target. On Mr. Johnson's recommendation, the Committee also awarded Mr. Mulhern an ad hoc grant of 4,000 RSUs that vest in 2014. The purpose of this grant was to address shortfalls in compensation compared to the Company's Benchmarking Peer Group and to provide a retention incentive for the pending merger with Duke Energy. Mr. Mulhern's total compensation in 2011 increased by 39.9% from the amount of total compensation he received in 2010, largely due to an increase in his accrued pension benefits.

Compensation of Other Named Executive Officers

For 2011, Mr. Johnson recommended and the Committee approved merit-based adjustments to the base salaries for Messrs. Lyash and McArthur. The Committee also approved a merit-based adjustment to Mr. Johnson's base salary. These increases to base salaries were supported by market data prepared by the Committee's independent compensation consultant. Mr. McArthur's base salary was adjusted to $502,640, representing a 3% increase to his previous salary of $488,000. Mr. Lyash's base salary was adjusted to $466,590, representing a 3% increase to his previous salary of $453,000. Mr. Johnson's base salary was adjusted to $1,030,000, representing a 4% increase to his previous salary of $990,000.

The Committee awarded Mr. Johnson, and on Mr. Johnson's recommendation, the Committee awarded Messrs. Lyash and McArthur 2011 MICP awards as described in the table below.

Named Executive Officer	2011 MICP Award	Percent of Target	Explanation of Award
William D. Johnson	$1,223,000	120%	Mr. Johnson led Progress Energy in achieving a record low in the OSHA recordable injury rate and lost days due to injury; achieving strong financial performance; managing capital projects within budget; improving the overall reliability and financial performance of the nuclear fleet; receiving positive customer feedback for system stability in the face of sustained summer heat and for storm restoration efforts after Hurricane Irene; improving efficiency while achieving sustainable savings and effective workforce plans through the Continuous Business Excellence initiative; and positioning our Parent for a successful merger with Duke Energy to create long-term benefits for shareholders and customers.
Jeffrey J. Lyash	$220,000	86%	Mr. Lyash played a significant role in improving the overall reliability and financial performance of the nuclear fleet; implementing our Parent's balanced solution strategy through the effective shutdown of the Weatherspoon Coal Plant and the start-up of a combined cycle plant; and managing the Energy Supply organization's O&M expenses below budget.
John R. McArthur	$305,000	111%	Mr. McArthur played a significant role in negotiating a favorable regulatory settlement in Florida to increase base rates through 2016, ensure cost recovery of expenditures associated with the proposed Levy Nuclear Plant, and resolve substantial portions of the prudence case for the Crystal River 3 Nuclear Plant; promoting reasonable environmental regulation with adequate compliance timeframes; and substantially achieving favorable regulatory approvals for the proposed merger of our Parent with Duke Energy.

With respect to long-term compensation, in 2011 each of the other NEOs received annual grants of RSUs and performance shares in accordance with their pre-established targets. The table below describes those grants.

Named Executive Officer	Restricted Stock Units Vesting in 1/3 Increments in 2012, 2013 and 2014	Performance Shares Vesting in 2014	Ad Hoc Restricted Stock Units Vesting in 2014
William D. Johnson	26,640	53,052	10,000
Jeffrey J. Lyash	6,043	12,190	4,000
John R. McArthur	6,510	13,132	4,000

Mr. Johnson's total compensation as shown in the "Summary Compensation Table" on page 37 of this Proxy Statement increased by 52.8% from the amount of total compensation he received in 2010, largely due to an increase in his accrued pension benefits.

Mr. Lyash's total compensation as shown in the "Summary Compensation Table" on page 37 of this Proxy Statement increased 36.2% from the amount of total compensation he received in 2010, largely due to an increase in his accrued pension benefits.

Mr. McArthur's total compensation as shown in the "Summary Compensation Table" on page 37 of this Proxy Statement increased 23.4% from the amount of total compensation he received in 2010, largely due to an increase in his stock awards.

IV. COMPENSATION COMMITTEE REPORT

The Committee has reviewed and discussed this CD&A with management as required by Item 407(e)(5) of Regulation S-K. Based on such review and discussions, the Committee recommended to the Company's Board of Directors that the CD&A be included in this Proxy Statement.

Organization and Compensation Committee

E. Marie McKee, Chair
John D. Baker II
Harris E. DeLoach, Jr.
James B. Hyler, Jr.
Robert W. Jones
Melquiades R. "Mel" Martinez
John H. Mullin, III

Unless specifically stated otherwise in any of the Company's filings under the Securities Act of 1933 or the Securities Exchange Act of 1934, the foregoing Compensation Committee Report shall not be deemed soliciting material, shall not be incorporated by reference into any such filings and shall not otherwise be deemed filed under such Acts.

SUMMARY COMPENSATION TABLE

The following Summary Compensation Table discloses the compensation during 2011 and the prior two fiscal years of our Chief Executive Officer, Chief Financial Officer, and the other three most highly paid executive officers who were serving at the end of 2011. Additionally, column (h) is dependent upon actuarial assumptions for determining the amounts included. A change in these actuarial assumptions would impact the values shown in this column. Where appropriate, we have indicated the major assumptions in the footnote to column (h).

Name and Principal Position (a)	Year (b)	Salary[1] ($) (c)	Stock Awards[2] ($) (e)	Non-Equity Incentive Plan Compensation[3] ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings[4] ($) (h)	All Other Compensation[5] ($) (i)	Total ($) (j)
William D. Johnson,	2011	$1,019,231	$3,995,779	$1,223,000	$2,887,591	$389,087	$9,514,688
Chairman[6]	2010	990,000	3,109,607	715,000	1,096,829	316,051	6,227,487
	2009	979,231	3,090,605	950,000	1,144,448	289,726	6,454,010
Mark F. Mulhern,	2011	$483,575	$985,090	$250,000	$874,620	$81,855	$2,675,140
Senior Vice President and	2010	443,269	667,916	205,000	517,696	77,672	1,911,553
Chief Financial Officer	2009	414,231	655,990	225,000	369,822	102,137	1,767,180
Jeffrey J. Lyash,	2011	$462,931	$990,481	$220,000	$583,916	$117,902	$2,375,230
Executive Vice President –	2010	453,000	711,892	195,000	281,882	102,290	1,744,064
Energy Supply	2009	450,846	728,120	235,000	244,369	292,061	1,950,396
Lloyd M. Yates,	2011	$457,822	$981,481	$220,000	$644,644	$97,533	$2,401,480
President and Chief	2010	448,000	704,043	195,000	342,925	80,548	1,770,516
Executive Officer	2009	445,846	720,683	235,000	308,815	119,432	1,829,776
John R. McArthur,	2011	$498,699	$1,053,252	$305,000	$100,633	$78,080	$2,035,664
Executive Vice President,	2010	488,000	766,911	220,000	81,601	92,677	1,649,189
General Counsel and	2009	485,846	780,070	250,000	74,001	116,381	1,706,298
Corporate Secretary							

[1] Consists of base salary earnings prior to (i) employee contributions to the Progress Energy 401(k) Savings & Stock Ownership Plan and (ii) voluntary deferrals, if any, under the MDCP. See "Deferred Compensation" discussion in Part II of the CD&A. Salary adjustments, if deemed appropriate, generally occur in March of each year.

[2] Includes the fair value of stock awards as of the grant date computed in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 718. The table below shows the fair value of stock awards granted in 2011 and the maximum potential payout for the performance shares granted in 2011, which are based on the March 16, 2011 closing stock price of $44.55.

2011 Stock Awards (column (e))				Maximum Potential Payout for Performance Shares	
	Grant Date Fair Value				
Name	Restricted Stock Units	Performance Shares	Total (column (e))	Maximum Percentage	Maximum Value
William D. Johnson	$1,632,312	$2,363,467	$3,995,779	200%	$4,726,934
Mark F. Mulhern	445,634	539,456	985,090	200%	1,078,912
Jeffrey J. Lyash	447,416	543,065	990,481	200%	1,086,130
Lloyd M. Yates	444,431	537,050	981,481	200%	1,074,100
John R. McArthur	468,221	585,031	1,053,252	200%	1,170,062

[3] Includes the awards earned under the MICP for 2009, 2010 and 2011 performance.

[4] Includes the change in present value of the accrued benefit under Progress Energy's Pension Plan, SERP, and/or the Progress Energy, Inc. Restoration Retirement Plan ("Restoration Plan") where applicable. The current incremental present values were determined using actuarial present value factors as provided by our actuarial consultants, Buck Consultants, based on FAS mortality assumptions post-age 65 and FAS discount rates for the years shown as follows:

FAS Discount Rates			
Year	**Pension Plan**	**SERP**	**Restoration Retirement Plan**
2011	4.70%	4.85%	4.45%
2010	5.50%	5.70%	5.00%
2009	5.95%	6.10%	5.45%

All NEOs participate in the Progress Energy Pension Plan ("Pension Plan"), a noncontributory defined benefit pension plan sponsored by Progress Energy for eligible non-bargaining employees. The Pension Plan was amended and restated as of January 1, 1999, to become a "cash balance" defined benefit plan. The cash balance benefit accrues each year with pay credits and interest credits. Pay credits range from 3% to 7% depending on the participants' age at the beginning of each plan year, January 1. Interest credits are added to cash balance accounts on December 31 of each year based on account balances as of January 1. Our Parent's Board of Directors approved the interest credit rate for the Pension Plan to be set at 5% for 2011. Generally, employees become vested under the Pension Plan on the earlier of the date they complete three years of vesting service or the date they reach normal retirement age, which is age 65. All of the NEOs have satisfied the eligibility requirements to receive their account benefit upon termination of employment. At benefit commencement, an employee has several lump sum and annuity payment options.

The Restoration Plan is a nonqualified deferred compensation plan that provides retirement benefits which otherwise would be provided under the Pension Plan, in the absence of limits imposed by applicable law on benefits which may be provided under the Pension Plan. The Restoration Plan is intended to constitute an unfunded retirement plan for a select group of management or highly compensated employees. Mr. McArthur is the only NEO who was a participant in the Restoration Plan in 2011. His accumulated benefit under the Restoration Plan was forfeited when he became a participant in the SERP on January 1, 2012.

In addition, column (h) includes the above market earnings on deferred compensation under the Deferred Compensation Plan for Key Management Employees. The 1996-1999 Deferred Compensation Plan for Key Management Employees provided a fixed rate of return of 10.0% on deferred amounts, which was 2.7% above the market interest rate of 7.3% at the time the plan was frozen in 1996. The Deferred Compensation Plan for Key Management Employees was discontinued in 2000 and replaced with the MDCP, which does not have a guaranteed rate of return. NEOs who were participants in the 1996-1999 Deferred Compensation Plan for Key Management Employees continue to receive plan benefits with respect to amounts deferred prior to its discontinuance in 2000. The above market earnings under the Deferred Compensation Plan for Key Management Employees are included in this column for Mr. Johnson. Changes in the accrued benefit under each plan for NEOs are shown in the table below:

2011 Change in Pension Value and Nonqualified Deferred Compensation Earnings (column (h))					
Name	**Change in Pension Plan**	**Change in SERP**	**Change in Restoration Plan**	**Above Market Earnings on Deferred Compensation Plan**	**Total (column (h))**
William D. Johnson	$99,263	$2,775,430	—	$12,898	$2,887,591
Mark F. Mulhern	84,410	790,210	—	—	874,620
Jeffrey J. Lyash	87,921	495,995	—	—	583,916
Lloyd M. Yates	62,002	582,642	—	—	644,644
John R. McArthur	52,951	—	$47,682	—	100,633

[5] Includes the following items: Company match contributions under the Progress Energy 401(k) Plan; deferred credits under the MDCP; perquisites; our Parent's payment of the FICA tax on the non-qualified retirement accrual and the tax gross-up on the imputed income of that tax payment; and cash dividends and cash dividend equivalents paid as the result of outstanding restricted stock or RSUs held in Company Plan accounts. The total value of perquisites and personal benefits received by Messrs. Mulhern and McArthur was less than $10,000 each. Thus, those amounts are excluded from this column. NEOs were compensated for these items as follows:

2011 All Other Compensation (column (i))

Name	Company Contributions under 401(k)	Deferred Credits under the MDCP	Perquisites (detailed in table below)	Imputed Income and Tax Gross-ups	Dividends	Total (column (i))
William D. Johnson	$14,700	$46,049	$128,616	$17,404	$182,318	$389,087
Mark F. Mulhern	14,700	13,850	—	8,653	44,652	81,855
Jeffrey J. Lyash	14,700	12,938	42,964	711	46,589	117,902
Lloyd M. Yates	14,700	12,633	18,700	5,216	46,284	97,533
John R. McArthur	13,663	15,074	—	799	48,544	78,080

Perquisites that exceed the greater of $25,000 or 10% of the total amount of perquisites and personal benefits for each officer are quantified in the table below. "Other" perquisites include luncheon and health club dues, spousal meals, Internet and telecom access, AD&D insurance, residential phone lines, and gifts.

2011 Perquisites (Component of column (i))

Name	Spousal Travel	Financial/Tax Planning	Home Security	Travel on Corporate Aircraft*	Other	Total Perquisites
William D. Johnson	$24,807	$6,000	$18,281	$73,226	$6,302	$128,616
Jeffrey J. Lyash	—	3,150	860	34,188	4,766	42,964
Lloyd M. Yates	—	2,000	250	14,276	2,174	18,700

* Reflects spousal travel on corporate aircraft for business-related purposes. It also includes personal travel for Mr. Johnson on corporate aircraft by him and his spouse valued at $26,488. Personal and spousal travel on corporate aircraft included in the table above is valued at the incremental cost to our Parent, which is calculated as the expense deduction disallowed under IRS rules.

[6] Mr. Johnson did not receive additional compensation for his service on the Board of Directors of Progress Energy.

2011 GRANTS OF PLAN-BASED AWARDS

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1] Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards[2] Threshold ($) (f)	Target ($) (g)	Maximum ($) (h)	All Other Stock Awards: Number of Shares of Stock or Units[3] ($) (i)	Grant Date Fair Value of Stock and Option Awards[4] ($) (j)
William D. Johnson, Chairman	MICP	$509,615	$1,019,231	$2,038,461					
	RSUs 3/16/11							36,640	$1,632,312
	PSSP 3/16/11				26,526	53,052	106,104		$2,363,467
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	MICP	$132,983	$265,966	$531,933					
	RSUs 3/16/11							10,003	$445,634
	PSSP 3/16/11				6,055	12,109	24,218		$539,456
Jeffrey J. Lyash, Executive Vice President – Energy Supply	MICP	$127,306	$254,612	$509,224					
	RSUs 3/16/11							10,043	$447,416
	PSSP 3/16/11				6,095	12,190	24,380		$543,065
Lloyd M. Yates, President and Chief Executive Officer	MICP	$125,901	$251,802	$503,604					
	RSUs 3/16/11							9,976	$444,431
	PSSP 3/16/11				6,028	12,055	24,110		$537,050
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	MICP	$137,142	$274,284	$548,568					
	RSUs 3/16/11							10,510	$468,221
	PSSP 3/16/11				6,566	13,132	26,264		$585,031

[1] Award amounts are shown at threshold, target, and maximum levels. The target award is calculated using the 2011 eligible earnings times the executive's target percentage. See target percentage in table on page 22 of the CD&A. Threshold is calculated at 50% of target and maximum is calculated at 200% of target. Actual award amounts paid are reflected in the Summary of Compensation Table under the "Non-Equity Incentive Plan Compensation" column.

[2] Reflects the potential payouts in shares of the 2011 PSSP grants. The grant size was calculated by multiplying the executive's salary as of January 1, 2011, times his 2011 PSSP target and dividing by the December 31, 2010, closing stock price of $43.48. The Threshold column reflects the payment level under the PSSP at 50% of the amount shown in the Target column. The amount shown in the maximum column is 200% of the target amount.

[3] Reflects the number of RSUs granted during 2011 under the 2007 Equity Incentive Plan. The number of shares granted was determined by multiplying the executive's salary as of January 1, 2011, times his 2011 RSU target and dividing by the December 31, 2010, closing stock price of $43.48.

[4] Reflects the grant date fair value of the award based on the following assumptions: market value of RSUs granted on March 16, 2011, based on the closing price of $44.55 per share, times the shares granted in column (i); market value of PSSP awards granted on March 16, 2011, based on the closing stock price on March 16, 2011, of $44.55 times the target number of shares in column (g). The 2011 PSSP grant payout is expected to be 100% of target.

DISCUSSION OF SUMMARY COMPENSATION TABLE AND GRANTS OF PLAN-BASED AWARDS TABLE

EMPLOYMENT AGREEMENTS

In 2007, Messrs. Johnson, Mulhern, Lyash, Yates and McArthur entered into employment agreements with Progress Energy or one of its subsidiaries, referred to collectively in this section as the "Company." The employment agreements replaced the previous employment agreements in effect for each of these officers.

The employment agreements provide for base salary, annual incentives, perquisites and participation in the various executive compensation plans offered to our senior executives. Upon expiration, the agreements are automatically extended by an additional year on January 1 of each year. Each employment agreement contains restrictive covenants imposing non-competition obligations, restricting solicitation of employees and protecting our confidential information and trade secrets for specified periods if the applicable officer is terminated without cause or otherwise becomes eligible for the benefits under the agreement.

Except for the application of previously granted years of service credit to our post-employment health and welfare plans as discussed below, the employment agreements do not affect the compensation, benefits or incentive targets payable to the applicable officers.

With respect to Mr. Johnson, the Employment Agreement specifies that the years of service credit we previously granted to him for purposes of determining eligibility and benefits in the SERP will also be applicable for purposes of determining eligibility and benefits in our post-employment health and welfare benefit plans. Mr. Johnson was awarded seven years of deemed service toward the benefits and vesting requirements of the SERP. However, as of 2008, Mr. Johnson reached the maximum service accrual and therefore benefit augmentation for deemed service is $0. Three of those years also were deemed to have been in service on the SMC for purposes of SERP eligibility.

Each Employment Agreement provides that if the applicable officer is terminated without cause or is constructively terminated (as defined in Paragraph 8(a)(i) of the agreement), then the officer will receive (i) severance equal to 2.99 times the officer's then-current base salary and (ii) reimbursement for the costs of continued coverage under certain of our health and welfare benefit plans for a period of up to 18 months.

In anticipation of the closing of the proposed merger with Duke Energy and the transition to Duke Energy's employment practices for executives, in October, 2011, the Company notified its NEOs that it would not renew their employment agreements upon expiration of the current terms. All of the NEOs' employment agreements expire on December 31, 2012.

OUTSTANDING EQUITY AWARDS AT 2011 FISCAL YEAR-END

	Stock Awards			
Name (a)	Number of Shares or Units of Stock That Have Not Vested ($) (g)[1]	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)[2]	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested ($) (i)[3]	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[3]
William D. Johnson, Chairman	73,938	$4,142,007	182,126	$8,376,699
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	18,765	$1,051,215	39,175	$1,822,975
Jeffrey J. Lyash, Executive Vice President – Energy Supply	19,195	$1,075,304	42,203	$1,934,707
Lloyd M. Yates, President and Chief Executive Officer	19,066	$1,068,077	41,734	$1,913,279
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	19,999	$1,120,344	45,486	$2,084,840

[1] Consists of outstanding RSUs as follows:

Number of Units of Stock That Have Not Vested (column (g))						
Stock Award	Vesting Date	William D. Johnson	Mark F. Mulhern	Jeffrey J. Lyash	Lloyd M. Yates	John R. McArthur
Restricted Stock Units	March 16, 2012	16,412	3,604	3,723	3,682	4,011
Restricted Stock Units	March 17, 2012	17,298	4,368	4,159	4,135	4,329
Restricted Stock Units	March 20, 2012	4,936	1,188	1,575	1,575	1,478
Restricted Stock Units	March 16, 2013	16,412	3,604	3,723	3,682	4,011
Restricted Stock Units	March 16, 2014	18,880	6,001	6,015	5,992	6,170
Total (column (g))		**73,938**	**18,765**	**19,195**	**19,066**	**19,999**

[2] Market value of units of stock that have not vested is based on a December 31, 2011, closing price of $56.02 per share.

[3] The 2009 PSSP grant vests on January 1, 2012; the 2010 grant vests on January 1, 2013; and the 2011 grant vests on January 1, 2014. Performance share value for the 2009 annual grant is expected to be at 50% of target while the 2010 annual grant and 2011 annual grant are expected to be 100% of target. The value in Column (j) is derived by multiplying the shares (rounded to the nearest whole share) times the December 31, 2011 closing stock price ($56.02). The difference between the calculated value and the noted value is attributable to fractional shares. See further discussion under "Performance Shares" in Part II of the CD&A. Outstanding performance shares for NEOs are shown in the table below:

Number of Unearned Shares, Units or Other Rights That Have Not Vested (column (i))						
Stock Award	**Vesting Date**	**William D. Johnson**	**Mark F. Mulhern**	**Jeffrey J. Lyash**	**Lloyd M. Yates**	**John R. McArthur**
Performance Shares	January 1, 2012	65,191	13,267	15,334	15,161	16,540
Performance Shares	January 1, 2013	61,838	13,332	14,209	14,053	15,307
Performance Shares	January 1, 2014	55,097	12,576	12,660	12,520	13,639
Total (column (i))		**182,126**	**39,175**	**42,203**	**41,734**	**45,486**

OPTION EXERCISES AND STOCK VESTED IN 2011

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise ($) (b)[1]	Value Realized on Exercise ($) (c)[2]	Number of Shares Acquired on Vesting ($) (d)[3]	Value Realized on Vesting ($) (e)[4]
William D. Johnson, Chairman	—	—	89,811	$4,066,089
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	7,000	$57,750	15,142	$684,966
Jeffrey J. Lyash, Executive Vice President – Energy Supply	—	—	20,006	$905,221
Lloyd M. Yates, President and Chief Executive Officer	—	—	19,963	$903,293
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	—	—	19,592	$886,572

[1] Reflects the number of shares of stock for options that were exercised in 2011.

[2] The value realized upon exercise is equal to the difference between the market price of the underlying securities at exercise and the exercise price of the options.

[3] Reflects the number of restricted stock shares, RSUs, and performance shares that vested in 2011 for NEOs as shown in the table below.

Number of Shares Acquired on Vesting (column (d))								
Stock Award	2011 Vesting Date	2011 Distribution Date	Stock Price	William D. Johnson	Mark F. Mulhern	Jeffrey J. Lyash	Lloyd M. Yates	John R. McArthur
Performance Shares	January 1	February 23	$45.59	54,861	8,179	11,599	11,599	10,782
Restricted Stock	March 14	March 14	$46.12	5,534	1,167	1,367	1,367	1,667
RSUs	March 16	March 16	$45.21	7,532	1,603	1,708	1,689	1,840
RSUs	March 17	March 17	$44.55	9,297	1,868	2,159	2,135	2,329
RSUs	March 18	March 18	$44.03	7,651	1,136	1,597	1,597	1,497
RSUs	March 20	March 21	$44.20	4,936	1,189	1,576	1,576	1,477
Total (column (d))				**89,811**	**15,142**	**20,006**	**19,963**	**19,592**

[4] The value of the 2008 performance share units was calculated using the closing stock price for Progress Energy Common Stock on the business day prior to when distribution occurred. The value of the restricted stock was calculated using the opening stock price for Progress Energy Common Stock three days prior to the day vesting occurred. The value of the RSUs was calculated using the closing stock price for Progress Energy Common Stock on the business day prior to when vesting occurred. Values realized on vesting during 2011 for NEOs are shown in the table below:

Value Realized on Vesting (column (e))								
Stock Award	**2011 Vesting Date**	**2011 Distribution Date**	**Stock Price**	**William D. Johnson**	**Mark F. Mulhern**	**Jeffrey J. Lyash**	**Lloyd M. Yates**	**John R. McArthur**
Performance Shares	January 1	February 23	$45.59	$2,501,113	$372,881	$528,798	$528,798	$491,551
Restricted Stock	March 14	March 14	46.12	255,228	53,822	63,046	63,046	76,882
RSUs	March 16	March 16	45.21	340,522	72,472	77,219	76,360	83,186
RSUs	March 17	March 17	44.55	414,181	83,219	96,183	95,114	103,757
RSUs	March 18	March 18	44.03	336,874	50,018	70,316	70,316	65,913
RSUs	March 20	March 21	44.20	218,171	52,554	69,659	69,659	65,283
Total (column (e))				**$4,066,089**	**$684,966**	**$905,221**	**$903,293**	**$886,572**

PENSION BENEFITS

Name (a)	Plan Name (b)	Number of Years Credited Service ($) (c)	Present Value of Accumulated Benefit[1] ($) (d)	Payments During Last Fiscal Year ($) (e)
William D. Johnson, Chairman	Progress Energy Pension Plan	19.3	$627,896	$0
	Supplemental Senior Executive Retirement Plan	26.3[2]	$11,063,301[3]	$0
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	Progress Energy Pension Plan	15.8	$411,117	$0
	Supplemental Senior Executive Retirement Plan	15.8	$2,395,365[4]	$0
Jeffrey J. Lyash, Executive Vice President – Energy Supply	Progress Energy Pension Plan	18.6	$422,617	$0
	Supplemental Senior Executive Retirement Plan	18.6	$2,136,806[5]	$0
Lloyd M. Yates, President and Chief Executive Officer	Progress Energy Pension Plan	13.1	$260,702	$0
	Supplemental Senior Executive Retirement Plan	13.1	$1,950,181[6]	$0
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	Progress Energy Pension Plan	10.1	$245,431	$0
	Restoration Retirement Plan	10.1	$210,297	$0

[1] Actuarial present value factors as provided by our actuarial consultants, Buck Consultants, based on FAS mortality assumptions post-age 65 and FAS discount rates as of December 31, 2011, for computation of accumulated benefit under the SERP and the Progress Energy Pension Plan were 4.85% and 4.70%, respectively. Additional details on the formulas for computing benefits under the SERP and Progress Energy Pension Plan can be found under the headings "Supplemental Senior Executive Retirement Plan" and "Other Broad-Based Benefits," respectively, in the CD&A.

[2] Includes seven years of deemed service. However, as of 2008, Mr. Johnson reached the maximum service accrual and therefore benefit augmentation for deemed service is $0.

[3] Based on an estimated annual benefit payable at age 65 of $1,153,308.

[4] Based on an estimated annual benefit payable at age 65 of $331,774.

[5] Based on estimated annual benefit payable at age 65 of $325,367.

[6] Based on estimated annual benefit payable at age 65 of $283,214.

NONQUALIFIED DEFERRED COMPENSATION

The table below shows the nonqualified deferred compensation for each of the NEOs. Information regarding details of the deferred compensation plans currently in effect can be found under the heading "Deferred Compensation" in Part II of the CD&A. In addition, the Deferred Compensation Plan for Key Management Employees is discussed in footnote 4 to the "Summary Compensation Table."

Name and Position (a)	Executive Contributions in Last FY[1] ($) (b)	Registrant Contributions in Last FY[2] ($) (c)	Aggregate Earnings in Last FY[3] ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE[4] ($) (f)
William D. Johnson, Chairman	$0	$46,049	$71,800	$0	$967,553
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	$0	$13,850	$16,097	($83,467)[5]	$179,741
Jeffrey J. Lyash, Executive Vice President – Energy Supply	$0	$12,938	$55,770	$0	$236,721
Lloyd M. Yates, President and Chief Executive Officer	$22,891	$12,633	$145,409	$0	$782,054
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	$24,935	$15,074	($5,446)	$0	$335,778

[1] Reflects salary deferred under the MDCP, which is reported as "Salary" in the Summary Compensation Table. For 2011, NEOs deferred the following percentages of their base salary: (i) Mr. Yates – 5%; and Mr. McArthur – 5%.

[2] Reflects registrant contributions under the MDCP, which is reported as "All Other Compensation" in the Summary Compensation Table.

[3] Includes aggregate earnings in the last fiscal year under the following nonqualified plans: MICP, MDCP, PSSP, and Deferred Compensation Plan for Key Management Employees. For Mr. Johnson, aggregate earnings includes above market earnings of $12,898 under the Deferred Compensation Plan for Key Management Employees, which is reported as "Change in Pension Value and Nonqualified Deferred Compensation Earnings" in the Summary Compensation Table.

[4] Includes December 31, 2011 balances under the following deferred compensation plans: MICP, PSSP, MDCP, and Deferred Compensation Plan for Key Management Employees. Balances for NEOs under each deferral plan are shown in the table below. The aggregate balances as of December 31, 2011 for each NEO includes the following aggregate amounts of prior deferrals of base salary, employer matching contributions, and above market earnings for nonqualified deferred compensation earnings that were previously earned and reported as compensation on the Summary Compensation Table for 2009 and 2010: (i) Mr. Johnson - $136,717; (ii) Mr. Mulhern - $64,158; (iii) Mr. Lyash - $24,736; (iv) Mr. Yates - $46,536; and (v) Mr. McArthur - $175,013. These amounts have been adjusted, pursuant to the terms of the Progress Energy Deferred Compensation Plans for investment performance (e.g. earnings and losses), deferrals, contributions, and distributions.

Aggregate Balance at Last FYE (column (f))					
Name	**MDCP**	**MICP**	**Deferred Compensation for Key Management Employees**	**PSSP**	**Total (column (f))**
William D. Johnson	$554,999	$105,398	$307,156	—	$967,553
Mark F. Mulhern	126,806	52,935	—	—	179,741
Jeffrey J. Lyash	236,721	—	—	—	236,721
Lloyd M. Yates	224,807	164,591	—	392,656	782,054
John R. McArthur	335,778	—	—	—	335,778

[5] Mr. Mulhern received distributions from his Management Incentive Deferred Compensation Plan: $41,418; and PSSP: $42,049.

CASH COMPENSATION AND VALUE OF VESTING EQUITY TABLE

The following table shows the actual cash compensation and value of vesting equity received in 2011 by the NEOs. The Committee believes that this table is important in order to distinguish between the actual cash and vested value received by each NEO as opposed to the grant date fair value of equity awards as shown in the Summary Compensation Table.

Name and Position	Base Salary (a)[1]	Annual Incentive (paid in 2011) (b)[2]	Restricted Stock/ Units Vesting (c)[3]	Performance Shares Vesting (d)[4]	Restricted Stock/Unit Dividends (e)[5]	Value Realized on Stock Option Exercises (f)[6]	Perquisites (g)[7]	Tax Gross-ups (h)[8]	Total
William D. Johnson, Chairman	$1,019,231	$715,000	$1,564,976	$2,501,113	$182,318	—	$64,273	$17,404	$6,064,318
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	$483,575	$205,000	$312,085	$372,881	$44,652	$57,750	$8,027	$8,653	$1,492,623
Jeffrey J. Lyash, Executive Vice President – Energy Supply	$462,931	$195,000	$376,423	$528,798	$46,589	—	$11,499	$711	$1,621,951
Lloyd M. Yates, President and Chief Executive Officer	$457,822	$195,000	$374,495	$528,798	$46,284	—	$5,619	$5,216	$1,613,234
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	$498,699	$220,000	$395,022	$491,551	$48,544	—	$9,557	$799	$1,664,172

[1] Consists of the total 2011 base salary earnings prior to (i) employee contributions to the Progress Energy 401(k) Plan and (ii) voluntary deferrals, if applicable, under the MDCP. For 2011, NEOs deferred the following amounts under the MDCP: (i) Mr. Yates – $22,891; and Mr. McArthur – $24,935.

[2] Reflects awards given under the MICP attributable to Plan Year 2010 and paid in 2011.

[3] Reflects the value of restricted stock and RSUs vesting in 2011. The value of the restricted stock was calculated using the opening stock price for Progress Energy Common Stock three days prior to the day vesting occurred. The value of the RSUs was calculated using the closing stock price for Progress Energy Common Stock on the business day prior to when vesting occurred.

[4] Reflects performance shares vested on January 1, 2011. The value of the 2008 performance share units is calculated using the closing stock price for Progress Energy Common Stock on the business day prior to when distribution occurred.

[5] Reflects cash dividends and cash dividend equivalents paid as the result of outstanding restricted stock or RSUs held in Company Plan accounts.

[6] Reflects the value realized upon exercise for options that were exercised in 2011. The value realized upon exercise is equal to the difference between the market price of the underlying securities at exercise and the exercise price of the options.

[7] Reflects the value of all perquisites provided during 2011. For a complete listing of the perquisites, see the "Executive Perquisites" in Part II of the CD&A. Perquisite details for each NEO are discussed in the Summary Compensation Table footnotes. Personal and spousal travel on corporate aircraft included in the table above is valued at the amounts imputed as income to the NEOs for tax purposes using the Standard Industry Fare Level ("SIFL") formula in accordance with IRS guidelines.

[8] Reflects our Parent's payment of the Medicare portion of the FICA tax on the non-qualified retirement accrual and the tax gross-up on the imputed income of that tax payment provided during 2011.

POTENTIAL PAYMENTS UPON TERMINATION
William D. Johnson, Chairman

Amounts reflected in the following table assume a triggering event occurred on December 31, 2011.

	Voluntary Termination[1] ($)	Early Retirement[1] ($)	Involuntary Not for Cause Termination[1] ($)	For Cause Termination[1] ($)	Involuntary or Good Reason Termination (CIC) ($)	Disability ($)	Death ($)
Compensation							
Base Salary—$1,030,000[2]	$0	$0	$3,079,700	$0	$6,180,000	$618,000	$0
Annual Incentive[3]	$0	$1,223,000	$0	$0	$1,030,000	$1,223,000	$1,223,000
Long-term Incentives:							
Performance Shares (PSSP)[4]							
2009 PSSP Grant	$0	$1,826,000	$0	$0	$3,652,000	$1,826,000	$1,826,000
2010 PSSP Grant	$0	$2,309,443	$0	$0	$3,464,165	$2,309,443	$2,309,443
2011 PSSP Grant	$0	$1,028,845	$0	$0	$3,086,534	$1,028,845	$1,028,845
Restricted Stock Units (RSU)[5]							
2007 RSU Grant	$0	$262,689	$0	$0	$276,515	$276,515	$276,515
2009 RSU Grant	$0	$888,281	$0	$0	$969,034	$969,034	$969,034
2010 RSU Grant	$0	$615,333	$0	$0	$843,885	$843,885	$843,885
2011 RSU Grant	$0	$824,054	$0	$0	$2,052,573	$0	$0
Benefits and Perquisites							
Deferred Compensation[6]	$967,552	$967,552	$967,552	$967,552	$967,552	$967,552	$967,552
Post-retirement Health Care[7]	$0	$0	$26,475	$0	$51,911	$0	$0
Executive AD&D Proceeds[8]	$0	$0	$0	$0	$0	$500,000	$500,000
280G Tax Gross-up[9]	$0	$0	$0	$0	$7,441,493	$0	$0
TOTAL	**$967,552**	**$9,945,197**	**$4,073,727**	**$967,552**	**$30,015,662**	**$10,562,274**	**$9,944,274**

[1] Mr. Johnson became eligible for early retirement at age 55 in January 2009. Therefore, under the voluntary termination, involuntary not for cause termination, and for cause termination scenarios, Mr. Johnson would be treated as having met the early retirement criteria under the Equity Incentive Plan, and would be paid out under the early retirement provisions of that plan. The payout would equal amounts listed under early retirement in the table above for performance shares and RSUs ($7,754,645). This amount would be added to the totals above for combined totals as follows: $8,722,197 under voluntary termination; $11,828,372 under involuntary not for cause termination; and $8,722,197 under for cause termination. Mr. Johnson is not eligible for normal retirement.

[2] There is no provision for payment of salary under voluntary termination, early retirement, for cause termination or death. In the event of involuntary not for cause termination, the salary continuation provision of Mr. Johnson's employment agreement requires a severance equal to 2.99 times his then current base salary ($1,030,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals three times the sum of annual salary plus target MICP award (($1,030,000 + $1,030,000) x 3). In the event of a long-term disability, Mr. Johnson would receive 60% of base salary during the period of his disability, offset by any Social Security benefits and Progress Energy Pension Plan payments. The long-term disability payment as shown in the table above represents an annual amount before offsets.

[3] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. In the event of involuntary or good reason termination (CIC), Mr. Johnson would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 100% times $1,030,000. In the event of early retirement, death or disability, Mr. Johnson would receive a pro-rata incentive award for the period worked during the year. For December 31, 2011, this is based on the full award. For 2011, Mr. Johnson's MICP award was $1,223,000.

[4] Amounts shown for performance shares are based on a December 31, 2011, closing price of $56.02 per share. Voluntary termination, involuntary not for cause termination, and for cause termination are not applicable, but see footnote 1 with respect to early retirement eligibility under these scenarios. In the event of early retirement or disability, a pro rata percentage of performance shares would vest based upon the period of employment during the performance measurement period and the extent that the performance factors are satisfied. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the target value of the award. In the event of death, the 2009 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2010 and 2011 performance grants, a pro-rata payment would be made based upon the target value of the award and time in the plan.

[5] Amounts shown for RSUs are based on a December 31, 2011, closing price of $56.02 per share. For a detailed description of outstanding RSUs, see the "Outstanding Equity Awards at 2011 Fiscal Year-End." Voluntary termination, involuntary not for cause termination, and for cause termination are not applicable, but see footnote 1 with respect to early retirement eligibility under these scenarios. In the event of early retirement, Mr. Johnson would receive a pro-rata percentage of all unvested RSUs, based upon the number of full months elapsed between the grant date and the date of early retirement. In the event of involuntary or good reason termination (CIC), all outstanding RSUs would vest immediately. Upon death or disability, all outstanding RSUs that are more than one year past their grant date would vest immediately. RSUs that are less than one year past their grant date would be forfeited. Mr. Johnson would immediately vest RSUs granted in 2007, 2009, and 2010, and would forfeit RSUs granted in 2011.

[6] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under each scenario.

[7] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. In the event of early retirement, Mr. Johnson would receive no additional benefits above what all full-time, nonbargaining employees would receive. Under involuntary not for cause termination, Mr. Johnson would be reimbursed for 18 months of COBRA premiums at $1,470.83 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Progress Energy-paid medical, dental and vision coverage in the same plan Mr. Johnson was participating in prior to termination for 36 months at $1,441.99 per month.

[8] Mr. Johnson would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[9] Upon a change in control, the Management Change-in-Control Plan provides for our Parent to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Johnson. Under IRC Section 280G, Mr. Johnson would be subject to excise tax on $13,328,855 of excess parachute payments above his base amount. Those excess parachute payments result in $2,665,771 of excise taxes, $4,669,363 of tax gross-ups, and $106,359 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Mark F. Mulhern, Senior Vice President and Chief Financial Officer

Amounts reflected in the following table assume a triggering event occurred on December 31, 2011.

	Voluntary Termination ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Disability ($)	Death ($)
Compensation						
Base Salary—$495,945[1]	$0	$1,482,876	$0	$1,537,430	$297,567	$0
Annual Incentive[2]	$0	$0	$0	$272,770	$250,000	$250,000
Long-term Incentives:						
Performance Shares (PSSP)[3]						
2009 PSSP Grant	$0	$0	$0	$743,217	$371,609	$371,609
2010 PSSP Grant	$0	$0	$0	$746,859	$497,906	$497,906
2011 PSSP Grant	$0	$0	$0	$704,508	$234,836	$234,836
Restricted Stock Units (RSU)[4]						
2007 RSU Grant	$0	$0	$0	$66,552	$66,552	$66,552
2009 RSU Grant	$0	$0	$0	$244,695	$244,695	$244,695
2010 RSU Grant	$0	$0	$0	$179,600	$179,600	$179,600
2011 RSU Grant	$0	$0	$0	$560,368	$0	$0
Benefits and Perquisites						
Deferred Compensation[5]	$179,741	$179,741	$179,741	$179,741	$179,741	$179,741
Post-retirement Health Care[6]	$0	$16,028	$0	$20,952	$0	$0
Executive AD&D Proceeds[7]	$0	$0	$0	$0	$500,000	$500,000
280G Tax Gross-up[8]	$0	$0	$0	$1,626,271	$0	$0
TOTAL	**$179,741**	**$1,678,645**	**$179,741**	**$6,882,963**	**$2,822,506**	**$2,524,939**

[1] There is no provision for payment of salary under voluntary termination, for cause termination or death. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, the salary continuation provision of Mr. Mulhern's employment agreement requires a severance equal to 2.99 times his then current base salary ($495,945) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals two times the sum of annual salary plus annual target MICP award (($495,945 + $272,770) x 2). In the event of a long-term disability, Mr. Mulhern would receive 60% of base salary during the period of his disability, offset by any Social Security benefits and Progress Energy Pension Plan payments. The long-term disability payment as shown in the table above represents an annual amount before offsets.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Mulhern would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $495,945. In the event of death or disability, Mr. Mulhern would receive a pro-rata incentive award for the period worked during the year. For December 31, 2011, this is based on the full award. For 2011, Mr. Mulhern's MICP award was $250,000.

[3] Amounts shown for performance shares are based on a December 31, 2011, closing price of $56.02 per share. Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the target value of the award. In the event of disability, a pro rata percentage of performance shares would vest based upon the period of employment during the performance measurement period and the extent that the performance factors are satisfied. In the event of death, the 2009 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2010 and 2011 performance grants, the target value of the award would be paid based upon time in the plan.

[4] Amounts shown for RSUs are based on a December 31, 2011, closing price of $56.02 per share. For a detailed description of outstanding RSUs, see the "Outstanding Equity Awards at 2011 Fiscal Year-End." Unvested RSUs would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding RSUs would vest immediately. Upon death or disability, all outstanding RSUs that are more than one year past their grant date would vest immediately. RSUs that are less than one year past their grant date would be forfeited. Mr. Mulhern would immediately vest RSUs granted in 2007, 2009, and 2010; and would forfeit RSUs granted in 2011.

[5] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under each scenario. Mr. Mulhern is not eligible for early retirement or normal retirement.

[6] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Mr. Mulhern is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. Mulhern would be reimbursed for 18 months of COBRA premiums at $890.45 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Progress Energy-paid medical, dental and vision coverage in the same plan Mr. Mulhern was participating in prior to termination for 24 months at $872.99 per month.

[7] Mr. Mulhern would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[8] Upon a change in control, the Management Change-in-Control Plan provides for our Parent to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Mulhern. Under IRC Section 280G, Mr. Mulhern would be subject to excise tax on $2,912,901 of excess parachute payments above his base amount. Those excess parachute payments result in $582,580 of excise taxes, $1,020,447 of tax gross-ups, and $23,244 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Jeffrey J. Lyash, Executive Vice President – Energy Supply

Amounts reflected in the following table assume a triggering event occurred on December 31, 2011.

	Voluntary Termination ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Disability ($)	Death ($)
Compensation						
Base Salary—$466,590[1]	$0	$1,395,104	$0	$2,169,644	$279,954	$0
Annual Incentive[2]	$0	$0	$0	$256,625	$220,000	$220,000
Long-term Incentives:						
Performance Shares (PSSP)[3]						
2009 PSSP Grant	$0	$0	$0	$859,011	$429,505	$429,505
2010 PSSP Grant	$0	$0	$0	$795,988	$530,659	$530,659
2011 PSSP Grant	$0	$0	$0	$709,213	$236,404	$236,404
Restricted Stock Units (RSU)[4]						
2007 RSU Grant	$0	$0	$0	$88,232	$88,232	$88,232
2009 RSU Grant	$0	$0	$0	$232,987	$232,987	$232,987
2010 RSU Grant	$0	$0	$0	$191,476	$191,476	$191,476
2011 RSU Grant	$0	$0	$0	$562,609	$0	$0
Benefits and Perquisites						
Deferred Compensation[5]	$236,721	$236,721	$236,721	$236,721	$236,721	$236,721
Post-retirement Health Care[6]	$0	$18,716	$0	$36,697	$0	$0
Executive AD&D Proceeds[7]	$0	$0	$0	$0	$500,000	$500,000
280G Tax Gross-up[8]	$0	$0	$0	$1,961,904	$0	$0
TOTAL	**$236,721**	**$1,650,541**	**$236,721**	**$8,101,107**	**$2,945,938**	**$2,665,984**

[1] There is no provision for payment of salary under voluntary termination, for cause termination or death. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, the salary continuation provision of Mr. Lyash's employment agreement requires a severance equal to 2.99 times his then current base salary ($466,590) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals three times the sum of annual salary plus annual target MICP award (($466,590 + $256,625) x 3). In the event of a long-term disability, Mr. Lyash would receive 60% of base salary during the period of his disability, offset by any Social Security benefits and Progress Energy Pension Plan payments. The long-term disability payment as shown in the table above represents an annual amount before offsets.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Lyash would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $466,590. In the event of death or disability, Mr. Lyash would receive a pro-rata incentive award for the period worked during the year. For December 31, 2011, this is based on the full award. For 2011, Mr. Lyash's MICP award was $220,000.

[3] Amounts shown for performance shares are based on a December 31, 2011, closing price of $56.02 per share. Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the target value of the award. In the event of disability, a pro rata percentage of performance shares would vest based upon the period of employment during the performance measurement period and the extent that the performance factors are satisfied. In the event of death, the 2009 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2010 and 2011 performance grants, the target value of the award would be paid based upon time in the plan.

[4] Amounts shown for RSUs are based on a December 31, 2011, closing price of $56.02 per share. For a detailed description of outstanding RSUs, see the "Outstanding Equity Awards at 2011 Fiscal Year-End." Unvested RSUs would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding RSUs would vest immediately. Upon death or disability, all outstanding RSUs that are more than one year past their grant date would vest immediately. RSUs that are less than one year past their grant date would be forfeited. Mr. Lyash would immediately vest RSUs granted in 2007, 2009, and 2010; and would forfeit RSUs granted in 2011.

[5] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under each scenario. Mr. Lyash is not eligible for early retirement or normal retirement.

[6] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Mr. Lyash is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. Lyash would be reimbursed for 18 months of COBRA premiums at $1,039.75 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Progress Energy-paid medical, dental and vision coverage in the same plan Mr. Lyash was participating in prior to termination for 36 months at $1,019.37 per month.

[7] Mr. Lyash would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[8] Upon a change in control, the Management Change-in-Control Plan provides for our Parent to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Lyash. Under IRC Section 280G, Mr. Lyash would be subject to excise tax on $3,514,070 of excess parachute payments above his base amount. Those excess parachute payments result in $702,814 of excise taxes, $1,231,049 of tax gross-ups, and $28,041 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Lloyd M. Yates, President and Chief Executive Officer

Amounts reflected in the following table assume a triggering event occurred on December 31, 2011.

	Voluntary Termination ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Disability ($)	Death ($)
Compensation						
Base Salary—$461,440[1]	$0	$1,379,706	$0	$2,145,696	$276,864	$0
Annual Incentive[2]	$0	$0	$0	$253,792	$220,000	$220,000
Long-term Incentives:						
Performance Shares (PSSP)[3]						
2009 PSSP Grant	$0	$0	$0	$849,319	$424,660	$424,660
2010 PSSP Grant	$0	$0	$0	$787,249	$524,833	$524,833
2011 PSSP Grant	$0	$0	$0	$701,370	$233,790	$233,790
Restricted Stock Units (RSU)[4]						
2007 RSU Grant	$0	$0	$0	$88,232	$88,232	$88,232
2009 RSU Grant	$0	$0	$0	$231,643	$231,643	$231,643
2010 RSU Grant	$0	$0	$0	$189,348	$189,348	$189,348
2011 RSU Grant	$0	$0	$0	$558,856	$0	$0
Benefits and Perquisites						
Deferred Compensation[5]	$782,054	$782,054	$782,054	$782,054	$782,054	$782,054
Post-retirement Health Care[6]	$0	$26,475	$0	$51,911	$0	$0
Executive AD&D Proceeds[7]	$0	$0	$0	$0	$500,000	$500,000
280G Tax Gross-up[8]	$0	$0	$0	$1,952,354	$0	$0
TOTAL	**$782,054**	**$2,188,235**	**$782,054**	**$8,591,824**	**$3,471,424**	**$3,194,560**

[1] There is no provision for payment of salary under voluntary termination, for cause termination or death. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, the salary continuation provision of Mr. Yates' employment agreement requires a severance equal to 2.99 times his then current base salary ($461,440) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals three times the sum of annual salary plus annual target MICP award (($461,440+ $253,792) x 3). In the event of a long-term disability, Mr. Yates would receive 60% of base salary during the period of his disability, offset by any Social Security benefits and Progress Energy Pension Plan payments. The long-term disability payment as shown in the table above represents an annual amount before offsets.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Yates would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $461,440. In the event of death or disability, Mr. Yates would receive a pro-rata incentive award for the period worked during the year. For December 31, 2011 this is based on the full award. For 2011, Mr. Yates' MICP award was $220,000.

[3] Amounts shown for performance shares are based on a December 31, 2011, closing price of $56.02 per share. Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the target value of the award. In the event of disability, a pro rata percentage of performance shares would vest based upon the period of employment during the performance measurement period and the extent that the performance factors are satisfied. In the event of death, the 2009 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2010 and 2011 performance grants, the target value of the award would be paid based upon time in the plan.

[4] Amounts shown for RSUs are based on a December 31, 2011, closing price of $56.02 per share. For a detailed description of outstanding RSUs, see the "Outstanding Equity Awards at 2011 Fiscal Year-End." Unvested RSUs would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding RSUs would vest immediately. Upon death or disability, all outstanding RSUs that are more than one year past their grant date would vest immediately. RSUs that are less than one year past their grant date would be forfeited. Mr. Yates would immediately vest RSUs granted in 2007, 2009, and 2010; and would forfeit RSUs granted in 2011.

[5] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under each scenario. Mr. Yates is not eligible for early retirement or normal retirement.

[6] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Mr. Yates is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. Yates would be reimbursed for 18 months of COBRA premiums at $1,470.83 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Progress Energy-paid medical, dental and vision coverage in the same plan Mr. Yates was participating in prior to termination for 36 months at $1,441.99 per month.

[7] Mr. Yates would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[8] Upon a change in control, the Management Change-in-Control Plan provides for our Parent to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Yates. Under IRC Section 280G, Mr. Yates would be subject to excise tax on $3,496,965 of excess parachute payments above his base amount. Those excess parachute payments result in $699,393 of excise taxes, $1,225,056 of tax gross-ups, and $27,905 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary

Amounts reflected in the following table assume a triggering event occurred on December 31, 2011.

	Voluntary Termination[1] ($)	Early Retirement[1] ($)	Involuntary Not for Cause Termination[1] ($)	For Cause Termination[1] ($)	Involuntary or Good Reason Termination (CIC) ($)	Disability ($)	Death ($)
Compensation							
Base Salary—$502,640[2]	$0	$0	$1,502,894	$0	$2,337,276	$301,584	$0
Annual Incentive[3]	$0	$0	$0	$0	$276,452	$305,000	$305,000
Long-term Incentives:							
Performance Shares (PSSP)[4]							
2009 PSSP Grant	$0	$463,285	$0	$0	$926,571	$463,285	$463,285
2010 PSSP Grant	$0	$571,665	$0	$0	$857,498	$571,665	$571,665
2011 PSSP Grant	$0	$254,686	$0	$0	$764,057	$254,686	$254,686
Restricted Stock Units (RSU)[5]							
2007 RSU Grant	$0	$78,658	$0	$0	$82,798	$82,798	$82,798
2009 RSU Grant	$0	$222,301	$0	$0	$242,511	$242,511	$242,511
2010 RSU Grant	$0	$150,402	$0	$0	$206,266	$206,266	$206,266
2011 RSU Grant	$0	$223,170	$0	$0	$588,770	$0	$0
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$1,915,600	$0	$0
Deferred Compensation[7]	$335,778	$335,778	$335,778	$335,778	$335,778	$335,778	$335,778
Post-retirement Health Care[8]	$0	$0	$17,837	$0	$34,975	$0	$0
Executive AD&D Proceeds[9]	$0	$0	$0	$0	$0	$500,000	$500,000
280G Tax Gross-up[10]	$0	$0	$0	$0	$3,162,063	$0	$0
TOTAL	**$335,778**	**$2,299,945**	**$1,856,509**	**$335,778**	**$11,730,615**	**$3,263,573**	**$2,961,989**

[1] Mr. McArthur became eligible for early retirement at age 55 with 10 years of service in December 2011 under the Equity Incentive Plan only. Therefore, under the voluntary termination, involuntary not for cause termination, and for cause termination scenarios, Mr. McArthur would be treated as having met the early retirement criteria under the Equity Incentive Plan and would be paid out under the early retirement provisions of that plan. The payout would equal amounts listed under early retirement in the table above for performance shares and RSUs ($1,964,167). This amount would be added to the totals above for combined totals as follows: $2,299,945 under voluntary termination; $3,820,676 under involuntary not for cause termination, and $2,299,945 under for cause termination. Mr. McArthur is not eligible for early retirement under the MICP as he has less than 15 years of service at December 31, 2011. Mr. McArthur is not eligible for normal retirement.

[2] There is no provision for payment of salary under voluntary termination, early retirement, for cause termination or death. In the event of involuntary not for cause termination, the salary continuation provision of Mr. McArthur's employment agreement requires a severance equal to 2.99 times his then current base salary ($502,640) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals three times the sum of annual salary plus annual target MICP award (($502,640 + $276,452) x 3). In the event of a long-term disability, Mr. McArthur would receive 60% of base salary during the period of his disability, offset by any Social Security benefits and Progress Energy Pension Plan payments. The long-term disability payment as shown in the table above represents an annual amount before offsets.

[3] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. McArthur is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. McArthur would receive 100% of his target bonus under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $502,640. In the event of death or disability, Mr. McArthur would receive a pro-rata incentive award for the period worked during the year. For December 31, 2011, this is based on the full award. For 2011, Mr. McArthur's MICP award was $305,000.

[4] Amounts shown for performance shares are based on a December 31, 2011, closing price of $56.02 per share. Voluntary termination, involuntary not for cause termination, and for cause termination are not applicable, but see footnote 1 with respect to early retirement eligibility under these scenarios. Mr. McArthur is not eligible for normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the target value of the award. In the event of early retirement or disability, a pro rata percentage of performance shares would vest based upon the period of employment during the performance measurement period and the extent that the performance factors are satisfied. In the event of death, the 2009 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2010 and 2011 performance grants, the target value of the award would be paid based upon time in the plan.

[5] Amounts shown for RSUs are based on a December 31, 2011, closing price of $56.02 per share. For a detailed description of outstanding RSUs, see the “Outstanding Equity Awards at 2011 Fiscal Year-End.” Voluntary termination, involuntary not for cause termination, and for cause termination are not applicable, but see footnote 1 with respect to early retirement eligibility under these scenarios. In the event of early retirement, Mr. McArthur would receive a pro rata percentage of all unvested RSUs, based upon the number of full months elapsed between the grant date and the date of early retirement. Mr. McArthur is not eligible for normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding RSUs would vest immediately. Upon death or disability, all outstanding RSUs that are more than one year past their grant date would vest immediately. RSUs that are less than one year past their grant date would be forfeited. Mr. McArthur would immediately vest RSUs granted in 2007, 2009, and 2010; and would forfeit RSUs granted in 2011.

[6] Mr. McArthur was not vested under the SERP as of December 31, 2011, so this is the incremental value due to accelerated vesting under involuntary or good reason termination (CIC). No accelerated vesting or incremental nonqualified pension benefit applies under any other scenario above.

[7] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under each scenario. Mr. McArthur is not eligible for early retirement or normal retirement.

[8] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Mr. McArthur is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. McArthur would be reimbursed for 18 months of COBRA premiums at $990.95 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Progress Energy-paid medical, dental and vision coverage in the same plan Mr. McArthur was participating in prior to termination for 36 months at $971.52 per month.

[9] Mr. McArthur would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[10] Upon a change in control, the Management Change-in-Control Plan provides for our Parent to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. McArthur. Under IRC Section 280G, Mr. McArthur would be subject to excise tax on $5,663,739 of excess parachute payments above his base amount. Those excess parachute payments result in $1,132,748 of excise taxes, $1,984,120 of tax gross-ups, and $45,195 of employer Medicare tax related to the excise tax payment.

DIRECTOR COMPENSATION

Our Board of Directors is comprised of employees of Progress Energy and its affiliates. They have multiple responsibilities within and provide various services to Progress Energy and its subsidiaries. The total compensation of Progress Energy's executive officers is designed to cover the full range of services they provide to Progress Energy and its subsidiaries, including the Company. Therefore, they do not receive an annual retainer, attendance fees or any additional compensation for their service as directors of the Company.

EQUITY COMPENSATION PLAN INFORMATION

There are no compensation plans under which equity securities of the Company are authorized for issuance. Our Parent sponsors an equity compensation plan in which certain employees of the Company participate.

PROPOSAL 2—ADVISORY (NONBINDING) VOTE ON EXECUTIVE COMPENSATION

Section 951 of the Dodd-Frank Wall Street Reform and Consumer Protection Act requires that companies seek a nonbinding shareholder vote to approve the compensation package of their named executive officers (“NEOs”), as disclosed in the annual proxy statement. This proposal, commonly known as a “say-on-pay” proposal, gives you as a shareholder the opportunity to express your views on the Company’s executive compensation program. The Company will follow the nonbinding resolution approved at the Company’s 2011 Annual Meeting of Shareholders, recommending that executive compensation be voted on by shareholders every year.

The advisory vote on executive compensation is a nonbinding vote on the compensation of the Company’s NEOs, as described in the Compensation Discussion and Analysis section, the tabular disclosure regarding such compensation and the accompanying narrative disclosure set forth in this Proxy Statement. The advisory vote is not a vote on the compensation of the Company’s Board of Directors or the Company’s compensation policies as they relate to risk management. Your vote will not directly affect or otherwise limit any existing compensation or award arrangements of any of our NEOs. Your vote is advisory and is not binding on the Board of Directors; however, the Compensation Committee of our Parent’s Board will take the outcome of the vote into account when considering future executive compensation arrangements.

At the Company’s 2011 Annual Meeting of Shareholders, a substantial majority of the votes cast on the say-on-pay proposal were voted in favor of the proposal. The Compensation Committee of our Parent’s Board believes this affirms our shareholders’ support of the Company’s approach to executive compensation.

The Company’s executive compensation philosophy aligns with that of our Parent, and is designed to provide competitive compensation consistent with key principles we believe are critical to our long-term success. The Company is committed to providing an executive compensation program that aligns our management team’s interests with shareholders’ expectations of earnings per share growth and a competitive dividend yield; effectively compensates our management team for actual performance over the short- and long-term; rewards operating performance results that are sustainable and consistent with reliable and efficient electric service; attracts and retains an experienced and effective management team; motivates and rewards our management team to produce growth and performance for our shareholders that are sustainable, consistent with prudent risk-taking, and based on sound corporate governance practices; and provides market competitive levels of target (i.e., opportunity) compensation.

We urge you to consider the following highlights of our 2011 executive compensation program in connection with your vote on this proposal:

- Our NEOs’ target (i.e., opportunity) total compensation levels are approximately 24% below the 50th percentile of our benchmarking peer group.

- We continue to provide only minimal executive perquisites (only those prevalent in the marketplace and that are conducive to promoting our desired business outcomes), and no tax gross-ups were made on any perquisites.

- Payments under the Management Incentive Compensation Plan and the Performance Share Sub-Plan are based on the achievement of multiple performance factors that we believe drive shareholder value.

- The Compensation Committee of our Parent’s Board made a number of decisions to reflect management’s achievement of key strategic initiatives, including: providing on average a 3% merit-based increase; awarding equity grants at target value; awarding ad hoc restricted stock unit grants to each of the NEOs to, among other things, provide a long-term retention incentive for the pending merger with Duke Energy; and increasing our Chairman’s annual incentive target opportunity from 85% to 100%.

See pages 20 to 36 of this Proxy Statement for more information regarding these elements of our executive program and decisions.

FOR THESE REASONS, THE BOARD OF DIRECTORS UNANIMOUSLY RECOMMENDS THAT THE SHAREHOLDERS VOTE, ON AN ADVISORY BASIS, "FOR" THE FOLLOWING RESOLUTION:

RESOLVED, THAT OUR SHAREHOLDERS APPROVE, ON AN ADVISORY BASIS, THE COMPENSATION OF OUR NAMED EXECUTIVE OFFICERS, AS DISCLOSED IN THE COMPENSATION DISCUSSION AND ANALYSIS, THE COMPENSATION TABLES AND ANY RELATED NARRATIVE DISCUSSION CONTAINED IN THIS PROXY STATEMENT.

REPORT OF THE AUDIT AND CORPORATE PERFORMANCE COMMITTEE

The Audit and Corporate Performance Committee of Progress Energy's Board of Directors (the "Audit Committee") has reviewed and discussed the audited financial statements of the Company for the fiscal year ended December 31, 2011, with the Company's management and with Deloitte & Touche LLP, the Company's independent registered public accounting firm. The Audit Committee discussed with Deloitte & Touche LLP the matters required to be discussed by Statement on Auditing Standards No. 114, as amended (AICPA, Professional Standards, Vol. 1 AU Section 380) as adopted by the Public Company Accounting Oversight Board in Rule 3200T, by the SEC's Regulation S-X, Rule 2-07, and by the NYSE's Corporate Governance Rules, as may be modified, amended or supplemented.

The Audit Committee has received the written disclosures and the letter from Deloitte & Touche LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant's communications with the Audit Committee concerning independence and has discussed with Deloitte & Touche LLP its independence.

Based upon the review and discussions noted above, the Audit Committee recommended to the Board of Directors that the Company's audited financial statements be included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2011, for filing with the SEC.

Audit and Corporate Performance Committee
of the Progress Energy Board of Directors

Theresa M. Stone, Chair
James E. Bostic, Jr.
W. Steven Jones
Charles W. Pryor, Jr.
Carlos A. Saladrigas
Alfred C. Tollison, Jr.

Unless specifically stated otherwise in any of the Company's filings under the Securities Act of 1933 or the Securities Exchange Act of 1934, the foregoing Report of the Audit Committee shall not be incorporated by reference into any such filings and shall not otherwise be deemed filed under such Acts.

DISCLOSURE OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM'S FEES

The Audit and Corporate Performance Committee of Progress Energy's Board of Directors (the "Audit Committee") has actively monitored all services provided by its independent registered public accounting firm, Deloitte & Touche LLP, the member firms of Deloitte & Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte") and the relationship between audit and nonaudit services provided by Deloitte. Progress Energy has adopted policies and procedures for preapproving all audit and permissible nonaudit services rendered by Deloitte, and the fees billed for those services. Those policies and procedures apply to Progress Energy and its subsidiaries, including the Company. Progress Energy's Controller is responsible to the Audit Committee for enforcement of this procedure, and for reporting noncompliance. Pursuant to the preapproval policy, the Audit Committee specifically preapproved the use of Deloitte for audit, audit-related and tax services.

The preapproval policy requires management to obtain specific preapproval from the Audit Committee for the use of Deloitte for any permissible nonaudit services, which generally are limited to tax services, including tax compliance, tax planning, and tax advice services such as return review and consultation and assistance. Other types of permissible nonaudit services will not be considered for approval except in limited instances, which could include circumstances in which proposed services provide significant economic or other benefits to us. In determining whether to approve these services, the Audit Committee will assess whether these services adversely impair the independence of Deloitte. Any permissible nonaudit services provided during a fiscal year that (i) do not aggregate to more than 5 percent of the total fees paid to Deloitte for all services rendered during that fiscal year and (ii) were not recognized as nonaudit services at the time of the engagement must be brought to the attention of Progress Energy's Controller for prompt submission to the Audit Committee for approval. These *de minimis* nonaudit services must be approved by the Audit Committee or its designated representative before the completion of the services. Nonaudit services that are specifically prohibited under the Sarbanes-Oxley Act Section 404, SEC rules, and Public Company Accounting Oversight Board ("PCAOB") rules are also specifically prohibited under the policy.

Prior to approval of permissible tax services by the Audit Committee, the policy requires Deloitte to (1) describe in writing to the Audit Committee (a) the scope of the service, the fee structure for the engagement and any side letter or other amendment to the engagement letter or any other agreement between the Company and Deloitte relating to the service and (b) any compensation arrangement or other agreement, such as a referral agreement, a referral fee or fee-sharing arrangement, between Deloitte and any person (other than the Company) with respect to the promoting, marketing or recommending of a transaction covered by the service; and (2) discuss with the Audit Committee the potential effects of the services on the independence of Deloitte.

The policy requires Progress Energy's Controller to update the Audit Committee throughout the year as to the services provided by Deloitte and the costs of those services. The policy also requires Deloitte to annually confirm its independence in accordance with SEC and NYSE standards. The Audit Committee will assess the adequacy of this policy as it deems necessary and revise accordingly.

Set forth in the table below is certain information relating to the aggregate fees billed by Deloitte for professional services rendered to us for the fiscal years ended December 31, 2011 and 2010.

	2011	2010
Audit fees	$1,901,000	$1,628,000
Audit-related fees	1,000	1,000
Tax fees	15,000	18,000
Other fees	–	–
Total fees	$1,917,000	$1,647,000

Audit fees include fees billed for services rendered in connection with (i) the audits of our annual financial statements; (ii) the reviews of the financial statements included in our Quarterly Reports on Form 10-Q; (iii) accounting consultations arising as part of the audits; and (iv) audit services in connection with statutory, regulatory or other filings, including comfort letters and consents in connection with SEC filings and financing transactions.

Audit-related fees include fees billed for accounting research tool subscriptions.

Tax fees include fees billed for tax compliance matters.

The Audit Committee has concluded that the provision of the nonaudit services listed above as “Tax fees” is compatible with maintaining Deloitte’s independence.

None of the services provided required approval by the Audit Committee pursuant to the *de minimis* waiver provisions described above.

PROPOSAL 3—RATIFICATION OF SELECTION OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Audit and Corporate Performance Committee of Progress Energy's Board of Directors (the "Audit Committee") has selected Deloitte & Touche LLP ("Deloitte & Touche") as our independent registered public accounting firm for the fiscal year ending December 31, 2012, and has directed that the Company's Board submit the selection of that independent registered public accounting firm for ratification by our shareholders at the 2012 Annual Meeting of Shareholders. Deloitte & Touche has served as the independent registered public accounting firm for our Company and its predecessors since 1930. In selecting Deloitte & Touche, the Audit Committee considered carefully Deloitte & Touche's previous performance for us, its independence with respect to the services to be performed and its general reputation for adherence to professional auditing standards. A representative of Deloitte & Touche will be present at the Annual Meeting of Shareholders, will have the opportunity to make a statement and will be available to respond to appropriate questions. Shareholder ratification of the selection of Deloitte & Touche as our independent registered public accounting firm is not required by our By-Laws or otherwise. However, we are submitting the selection of Deloitte & Touche to the shareholders for ratification as a matter of good corporate practice. If the shareholders fail to ratify the selection, the Audit Committee will reconsider whether or not to retain Deloitte & Touche. Even if the shareholders ratify the selection, the Audit Committee, in its discretion, may direct the appointment of a different independent registered public accounting firm at any time during the year if it is determined that such a change would be in the best interest of the Company and its shareholders.

Valid proxies received pursuant to this solicitation will be voted in the manner specified. Where no specification is made, the shares represented by the accompanying proxy will be voted **"FOR"** the ratification of the selection of Deloitte & Touche as our independent registered public accounting firm. Votes (other than votes withheld) will be cast pursuant to the accompanying proxy for the ratification of the selection of Deloitte & Touche.

The proposal to ratify the selection of Deloitte & Touche to serve as our independent registered public accounting firm for the fiscal year ending December 31, 2012, requires approval by a majority of the votes actually cast by holders of shares present in person or represented by proxy at the online Annual Meeting of Shareholders and entitled to vote thereon. Abstentions from voting and broker nonvotes will not count as shares voted and will not have the effect of a "negative" vote, as described in more detail under the heading "PROXIES" on page 2.

THE BOARD OF DIRECTORS UNANIMOUSLY RECOMMENDS A VOTE "FOR" THE RATIFICATION OF THE SELECTION OF DELOITTE & TOUCHE AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM.

FINANCIAL STATEMENTS

Our 2011 Annual Report, which includes our Parent's consolidated financial statements as of December 31, 2011, and 2010, and for each of the three years in the period ended December 31, 2011, together with the report of Deloitte & Touche LLP, our independent registered public accounting firm, was provided to those who were shareholders of record as of the close of business on March 2, 2012.

FUTURE SHAREHOLDER PROPOSALS

Shareholder proposals submitted for inclusion in the proxy statement for our 2013 Annual Meeting must be received no later than December 1, 2012, at our principal executive offices, addressed to the attention of:

Corporate Secretary
Carolina Power & Light Company d/b/a
Progress Energy Carolinas, Inc.
P.O. Box 1551
Raleigh, North Carolina 27602-1551

Upon receipt of any such proposal, we will determine whether or not to include such proposal in the proxy statement and proxy in accordance with regulations governing the solicitation of proxies.

In order for a shareholder to nominate a candidate for director, under our By-Laws timely notice of the nomination must be received by the Corporate Secretary of the Company either by personal delivery or by United States registered or certified mail, postage pre-paid, not later than the close of business on the 120th calendar day before the date our proxy statement was released to shareholders in connection with the previous year's annual meeting. In no event shall the public announcement of an adjournment or postponement of an annual meeting or the fact that an annual meeting is held after the anniversary of the preceding annual meeting commence a new time period for a shareholder's giving of notice as described above. The shareholder filing the notice of nomination must include:

- As to the shareholder giving the notice:
  - the name and address of record of the shareholder who intends to make the nomination, the beneficial owner, if any, on whose behalf the nomination is made and of the person or persons to be nominated;
  - the class and number of our shares that are owned by the shareholder and such beneficial owner;
  - a representation that the shareholder is a holder of record of our shares entitled to vote at such meeting and intends to appear in person or by proxy at the meeting to nominate the person or persons specified in the notice; and
  - a description of all arrangements, understandings or relationships between the shareholder and each nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the shareholder.
- As to each person whom the shareholder proposes to nominate for election as a director:
  - the name, age, business address and, if known, residence address of such person;
  - the principal occupation or employment of such person;
  - the class and number of shares of our stock that are beneficially owned by such person;

- any other information relating to such person that is required to be disclosed in solicitations of proxies for election of directors or is otherwise required by the rules and regulations of the SEC promulgated under the Securities Exchange Act of 1934; and

- the written consent of such person to be named in the proxy statement as a nominee and to serve as a director if elected.

In order for a shareholder to bring other business before a shareholder meeting, we must receive timely notice of the proposal not later than the close of business on the 60th day before the first anniversary of the immediately preceding year's annual meeting. Such notice must include:

- the information described above with respect to the shareholder proposing such business;

- a brief description of the business desired to be brought before the annual meeting, including the complete text of any resolutions to be presented at the annual meeting, and the reasons for conducting such business at the annual meeting; and

- any material interest of such shareholder in such business.

These requirements are separate from the requirements a shareholder must meet to have a proposal included in our proxy statement.

Any shareholder desiring a copy of our By-Laws will be furnished one without charge upon written request to the Corporate Secretary. A copy of the By-Laws, as amended and restated on May 13, 2009, was filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, and is available through the SEC's website at *www.sec.gov.*

OTHER BUSINESS

The Board of Directors does not intend to bring any business before the meeting other than that stated in this Proxy Statement. The Board knows of no other matter to come before the meeting. If other matters are properly brought before the meeting, it is the intention of the Board of Directors that the persons named in the enclosed proxy will vote on such matters pursuant to the proxy in accordance with their best judgment.

Exhibit A

POLICY AND PROCEDURES WITH RESPECT TO RELATED PERSON TRANSACTIONS

A. Policy Statement

The Company's Board of Directors (the "Board") recognizes that Related Person Transactions (as defined below) can present heightened risks of conflicts of interest or improper valuation or the perception thereof. Accordingly, the Company's general policy is to avoid Related Person Transactions. Nevertheless, the Company recognizes that there are situations where Related Person Transactions might be in, or might not be inconsistent with, the best interests of the Company and its stockholders. These situations could include (but are not limited to) situations where the Company might obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when the Company provides products or services to Related Persons (as defined below) on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. The Company, therefore, has adopted the procedures set forth below for the review, approval or ratification of Related Person Transactions.

This Policy has been approved by the Board. The Corporate Governance Committee (the "Committee") will review and may recommend to the Board amendments to this Policy from time to time.

B. Related Person Transactions

For the purposes of this Policy, a "Related Person Transaction" is a transaction, arrangement or relationship, including any indebtedness or guarantee of indebtedness, (or any series of similar transactions, arrangements or relationships) in which the Company (including any of its subsidiaries) was, is or will be a participant and the amount involved exceeds $120,000, and in which any Related Person had, has or will have a direct or indirect material interest.

For purposes of this Policy, a "Related Person" means:

1. any person who is, or at any time since the beginning of the Company's last fiscal year was, a director or executive officer (i.e. members of the Senior Management Committee and the Controller) of the Company, Progress Energy Carolinas, Inc., or Progress Energy Florida, Inc. or a nominee to become a director of the Company, Progress Energy Carolinas, Inc., or Progress Energy Florida, Inc.;

2. any person who is known to be the beneficial owner of more than 5% of any class of the voting securities of the Company or its subsidiaries;

3. any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law of the director, executive officer, nominee or more than 5% beneficial owner, and any person (other than a tenant or employee) sharing the household of such director, executive officer, nominee or more than 5% beneficial owner; and

4. any firm, corporation or other entity in which any of the foregoing persons is employed or is a general partner or principal or in a similar position or in which such person has a 5% or greater beneficial ownership interest.

C. Approval Procedures

1. The Board has determined that the Committee is best suited to review and approve Related Person Transactions. Accordingly, at each calendar year's first regularly scheduled Committee meeting, management shall recommend Related Person Transactions to be entered into by the Company for that calendar year, including the proposed aggregate value of such transactions if applicable. After review, the Committee shall approve or disapprove such transactions and at each subsequently scheduled meeting, management shall update the Committee as to any material change to those proposed transactions.

2. In determining whether to approve or disapprove each related person transaction, the Committee will consider various factors, including the following:

    - the identity of the related person;
    - the nature of the related person's interest in the particular transaction;
    - the approximate dollar amount involved in the transaction;
    - the approximate dollar value of the related person's interest in the transaction;
    - whether the related person's interest in the transaction conflicts with his obligations to the Company and its shareholders;
    - whether the transaction will provide the related person with an unfair advantage in his dealings with the Company; and
    - whether the transaction will affect the related person's ability to act in the best interests of the Company and its shareholders

The Committee will only approve those related person transactions that are in, or are not inconsistent with, the best interests of the Company and its shareholders.

3. In the event management recommends any further Related Person Transactions subsequent to the first calendar year meeting, such transactions may be presented to the Committee for approval at the next Committee meeting. In these instances in which the Legal Department, in consultation with the President and Chief Operating Officer, determines that it is not practicable or desirable for the Company to wait until the next Committee meeting, any further Related Person Transactions shall be submitted to the Chair of the Committee (who will possess delegated authority to act between Committee meetings). The Chair of the Committee shall report to the Committee at the next Committee meeting any approval under this Policy pursuant to his/her delegated authority.

4. No member of the Committee shall participate in any review, consideration or approval of any Related Person Transaction with respect to which such member or any of his or her immediate family members is the Related Person. The Committee (or the Chair) shall approve only those Related Person Transactions that are in, or are not inconsistent with, the best interests of the Company and its stockholders, as the Committee (or the Chair) determines in good faith. The Committee or Chair, as applicable, shall convey the decision to the President and Chief Operating Officer, who shall convey the decision to the appropriate persons within the Company.

D. Ratification Procedures

In the event the Company's Chief Executive Officer, President and Chief Operating Officer, Chief Financial Officer or General Counsel becomes aware of a Related Person Transaction that has not been previously approved or previously ratified under this Policy, said officer shall immediately notify the Committee or Chair of the Committee, and the Committee or Chair shall consider all of the relevant facts and circumstances regarding the Related Person Transaction. Based on the conclusions reached, the Committee or the Chair shall evaluate all options, including but not limited to ratification, amendment, termination or recession of the Related Person Transaction, and determine how to proceed.

E. Review of Ongoing Transactions

At the Committee's first meeting of each calendar year, the Committee shall review any previously approved or ratified Related Person Transactions that remain ongoing and have a remaining term of more than six months or remaining amounts payable to or receivable from the Company of more than $120,000. Based on all relevant facts and circumstances, taking into consideration the Company's contractual obligations, the Committee shall determine if it is in the best interests of the Company and its stockholders to continue, modify or terminate the Related Person Transaction.

F. Disclosure

All Related Person Transactions are to be disclosed in the filings of the Company, Progress Energy Carolinas, Inc. or Progress Energy Florida, Inc., as applicable, with the Securities and Exchange Commission as required by the Securities Act of 1933 and the Securities Exchange Act of 1934 and related rules. Furthermore, all Related Person Transactions shall be disclosed to the Corporate Governance Committee of the Board and any material Related Person Transaction shall be disclosed to the full Board of Directors.

The material features of this Policy shall be disclosed in the Company's annual report on Form 10-K or in the Company's proxy statement, as required by applicable laws, rules and regulations.

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