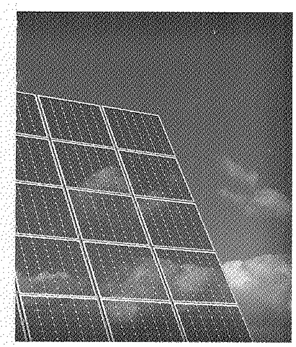
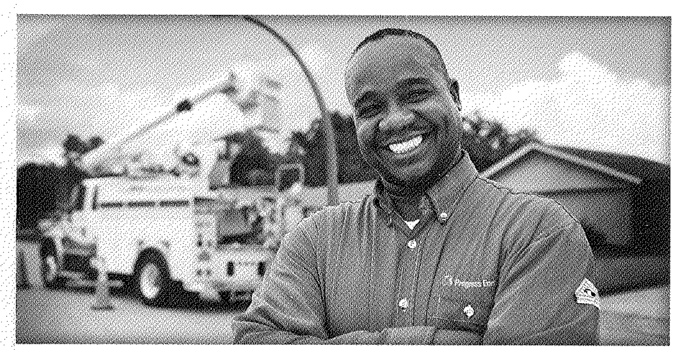
2010 Annual Report | Notice of Annual Meeting | Proxy Statement

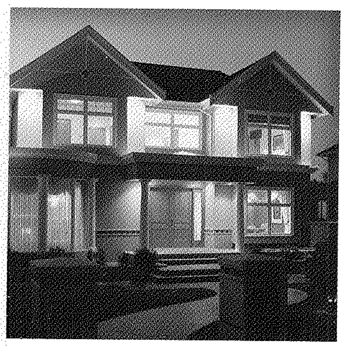


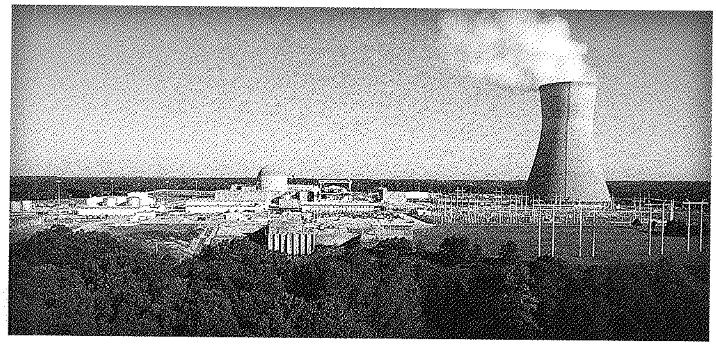


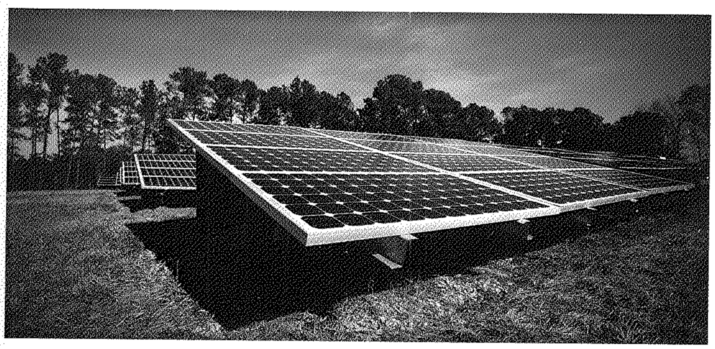
Manage the present. Create the future.

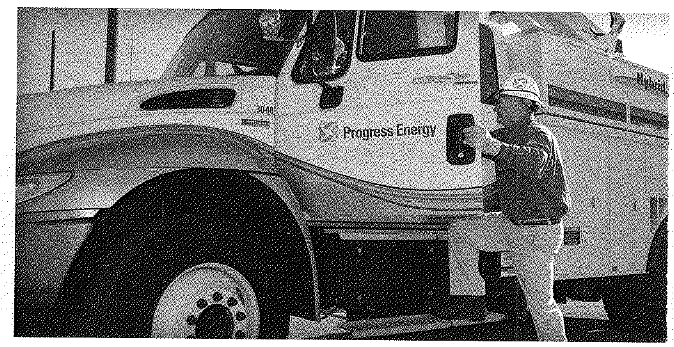
BUILD NEW CONNECTIONS.

Progress Energy









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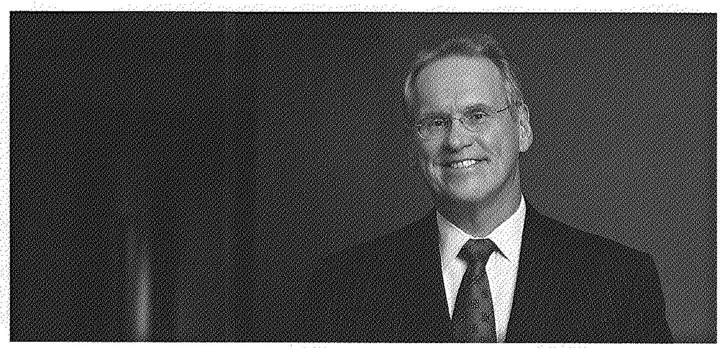


A MESSAGE FROM OUR CEO

DEAR SHAREHOLDERS:

This report in early spring 2011 comes after a year of strong results at Progress Energy and during a time of major transition for our company and industry. I am very pleased with how our employees continue to build on success in our core mission of serving customers and in our financial returns for shareholders.

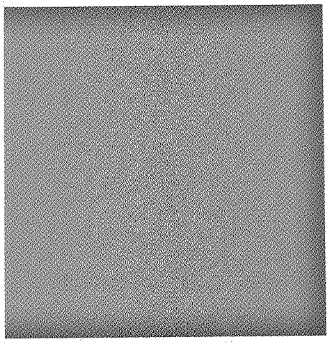
Our company and Duke Energy, our utility neighbor based in Charlotte, N.C., announced a strategic business combination in January 2011. Once approved, this combination will create the largest utility in the United States. We believe this is a natural fit that will benefit both customers and shareholders. It will mean a stronger company positioned to create a better future.

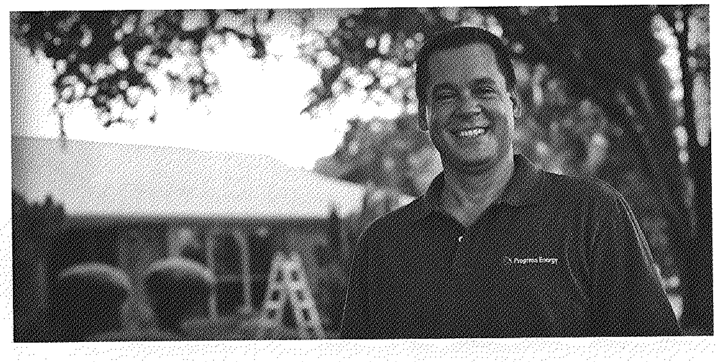
Meanwhile, as we move through the merger approval process in 2011 and plan how best to integrate the two organizations, we are keeping a sharp focus on excelling in the daily fundamentals and meeting our current responsibilities. In this business, we can't afford to miss a beat. Operational focus and financial discipline are essential even as we adapt to a changing industry and prepare for the decades to come.

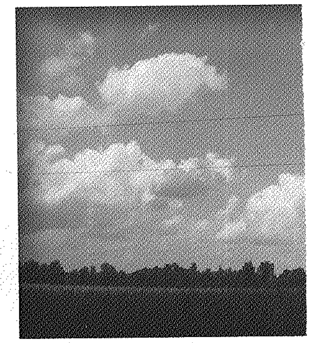
2010 Performance

Progress Energy delivered a 12.6 percent total return to shareholders in 2010 (dividend plus stock-price appreciation for the 12 months) and for the fifth consecutive year achieved ongoing earnings per share in our original targeted range or higher. Helped by favorable weather, we slightly exceeded the top end of the range in 2010. We also maintained our long record of commitment to the dividend.

The economy is slowly recovering in the areas we serve in the Carolinas and Florida. Our net average number of







total customers grew by 14,000 in 2010, including the first customer growth in Florida in three years. We are encouraged by the prospects for growth in our customer base and the overall economy.

Progress Energy provided reliable, affordable service to our 3.1 million customers even in a year that had more than its share of severe weather and extreme temperatures. We also were pleased that the Florida Public Service Commission approved a constructive rate settlement that stabilized our base rates through 2012.

Our company continues to earn positive external recognition for environmental stewardship and customer service. Progress Energy was named to the Dow Jones Sustainability Index for the sixth consecutive year, and Progress Energy Carolinas was ranked third in the South and fifth nationwide in customer satisfaction among large utilities in the latest J.D. Power and Associates survey of business customers.

An industry in transition

The United States' electric power system is at the front edge of a long-term transformation. It is being driven by new governmental policies, technological developments and aging facilities, as well as by changes in our economy and customer behavior.

This transformation will require retiring older coal-fired plants, modernizing the electric grid and investing in clean energy facilities that range from large nuclear plants to small renewable-energy projects. And it will require understanding electricity customers at a deeper level. These and other changes will mean an overall power system that is getting smarter, cleaner and more secure.

Making these changes will require enormous capital investments that will be reflected in what customers pay for electricity. Along with others in our industry, I am advocating that we work in a collaborative way with policymakers and regulators to manage this transition in a cost-effective,

orderly way. We need a flexible, balanced approach to energy and environmental policy that minimizes the cumulative cost impact on customers and maintains the reliability of service that underpins our economy and way of life.

A strategic merger

Progress Energy and Duke Energy will merge in a stock-for-stock transaction according to the definitive merger agreement unanimously approved by both companies' boards of directors in January 2011. This strategic combination, to be known by the Duke Energy corporate name, will have an enterprise value of about $65 billion and a regulated customer base of more than 7 million households and businesses in six states.

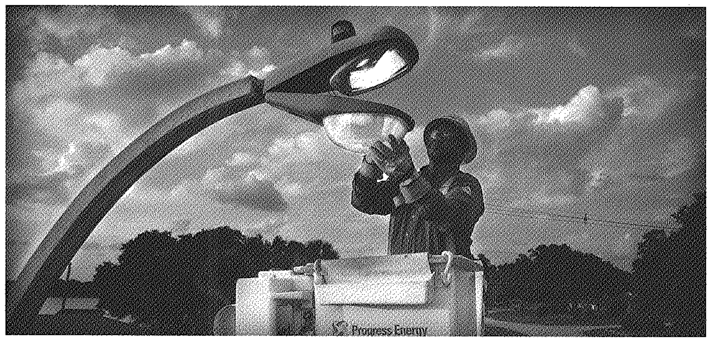
By joining forces with Duke Energy, our neighbor for more than a century, we will be in a better position to manage the transformation occurring in our industry and hold down some of the rate pressure on our customers. The combined company will have greater financial strength to support potential dividend growth while raising the large amounts of capital needed to modernize our system, meet new environmental rules and keep up with population growth.

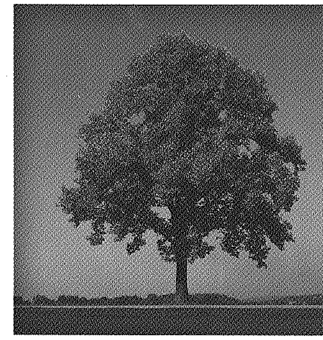
Later this year, shareholders will receive more information about the Duke-Progress merger and the opportunity to vote on the transaction. The merger must be approved by the shareholders of both companies and by several state and

FINANCIAL HIGHLIGHTS

Years ended December 31 *(in millions, except per share data)*	**2010**	2009	2008
Financial Data			
Operating revenues	**$10,190**	$9,885	$9,167
Net income attributable to controlling interests	**856**	757	830
Income from continuing operations	**867**	840	778
Ongoing earnings per common share*	**3.06**	3.03	2.96
Reported GAAP earnings per common share	**2.95**	2.71	3.17
Average common shares outstanding	**291**	279	262
Common Stock Data			
Return on average common stock equity (percent)	**8.70**	8.13	9.59
Book value per common share	**$34.05**	$33.53	$32.97
Market value per common share (closing)	**$43.48**	$41.01	$39.85

*See page 125 for a reconciliation of ongoing earnings per share to reported GAAP earnings per share.





federal agencies. We are targeting a closing by the end of 2011. When the merger is completed, I will become the president and chief executive officer of the new company. Duke Energy's current chairman, president and chief executive officer, Jim Rogers, will become the executive chairman.

Focused on the business at hand

Merger approvals and integration planning will require attention in 2011. Even so, we are keeping our main focus on the business at hand this year at Progress Energy, and we have a clear plan for success.

Our approach starts, as always, with a relentless focus on the fundamentals of this business: safety, operational excellence, customer satisfaction and aggressive cost management. It also includes continuing efforts to foster a workplace culture with high standards of personal behavior and accountability. This culture is a prime reason we are able to attract and retain the high caliber of employees we need.

In addition, our company has four areas of special focus in 2011: (1) improving the overall performance of our nuclear plants; (2) accelerating Continuous Business Excellence, our companywide initiative to improve efficiency and service while achieving sustainable savings; (3) optimizing our Balanced Solution Strategy, a diverse portfolio of investments that enable us to meet customers' growing needs and new public policies while creating long-term value; and (4) achieving timely merger approvals and effective integration planning to position the combined Duke-Progress for success.

Building new connections

Progress Energy has been closely connected to the communities we serve for more than a century, and we're proud of our long tradition of dependable service and active community involvement. We also tend to have long-term connections with our shareholders, based on our consistent track record of financial performance and the reliability of our dividend.

In this time of transition for our company and industry, the merger with Duke Energy represents a unique opportunity. We can build on the successful history of our two companies and form new connections on a larger scale. Stay tuned for more information about the merger in the weeks ahead.

In closing, I want to express my deep appreciation for the superb commitment and hard work of our employees and for the confidence that so many of you reading this report have shown in Progress Energy. We're intent on earning your confidence day after day as we manage the present, create the future and build new connections.

William D. Johnson

William D. Johnson
Chairman, President and Chief Executive Officer
March 2011

Cautionary statements regarding forward-looking information

This document contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words or phrases such as "may," "will," "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "target," "forecast," and other words and terms of similar meaning. Forward-looking statements involve estimates, expectations, projections, goals, forecasts, assumptions, risks and uncertainties. Progress Energy cautions readers that any forward-looking statement is not a guarantee of future performance and that actual results could differ materially from those contained in the forward-looking statement. Such forward-looking statements include, but are not limited to, statements about the benefits of the proposed merger involving Duke Energy and Progress Energy, including future financial and operating results, Progress Energy's or Duke Energy's plans, objectives, expectations and intentions, the expected timing of completion of the transaction, and other statements that are not historical facts. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include risks and uncertainties relating to: the ability to obtain the requisite Duke Energy and Progress Energy shareholder approvals; the risk that Progress Energy or Duke Energy may be unable to obtain governmental and regulatory approvals required for the merger, or required governmental and regulatory approvals may delay the merger or result in the imposition of conditions that could cause the parties to abandon the merger; the risk that a condition to closing of the merger may not be satisfied; the timing to consummate the proposed merger; the risk that the businesses will not be integrated successfully; the risk that the cost savings and any other synergies from the transaction may not be fully realized or may take longer to realize than expected; disruption from the transaction making it more difficult to maintain relationships with customers, employees or suppliers; the diversion of management time on merger-related issues; general worldwide economic conditions and related uncertainties; the effect of changes in governmental regulations; and other factors we discuss or refer to in the "Risk Factors" section of our most recent Annual Report on Form 10-K filed with the Securities and Exchange Commission (SEC). These risks, as well as other risks associated with the merger, will be more fully discussed in the joint proxy statement/prospectus that will be included in the Registration Statement on Form S-4 that will be filed with the SEC in connection with the merger. Additional risks and uncertainties are identified and discussed in Progress Energy's and Duke Energy's reports filed with the SEC and available at the SEC's website at www.sec.gov. Each forward-looking statement speaks only as of the date of the particular statement and neither Progress Energy nor Duke Energy undertakes any obligation to update or revise its forward-looking statements, whether as a result of new information, future events or otherwise.

Additional information and where to find it

This document does not constitute an offer to sell or the solicitation of an offer to buy any securities, or a solicitation of any vote or approval, nor shall there be any sale of securities in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction. In connection with the proposed merger between Duke Energy and Progress Energy, Duke Energy will file with the SEC a Registration Statement on Form S-4 that will include a joint proxy statement of Duke Energy and Progress Energy that also constitutes a prospectus of Duke Energy. Duke Energy and Progress Energy will deliver the joint proxy statement/prospectus to their respective shareholders. **Duke Energy and Progress Energy urge investors and shareholders to read the joint proxy statement/prospectus regarding the proposed merger when it becomes available, as well as other documents filed with the SEC, because they will contain important information.** You may obtain copies of all documents filed with the SEC regarding this transaction, free of charge, at the SEC's website (www.sec.gov). You may also obtain these documents, free of charge, from Duke Energy's website (www.duke-energy.com) under the heading "Investors" and then under the heading "Financials/SEC Filings." You may also obtain these documents, free of charge, from Progress Energy's website (www.progress-energy.com/investor).

Participants in the merger solicitation

Duke Energy, Progress Energy, and their respective directors, executive officers and certain other members of management and employees may be soliciting proxies from Duke Energy and Progress Energy shareholders in favor of the merger and related matters. Information regarding the persons who may, under the rules of the SEC, be deemed participants in the solicitation of Duke Energy and Progress Energy shareholders in connection with the proposed merger will be set forth in the joint proxy statement/prospectus when it is filed with the SEC. You can find information about Duke Energy's executive officers and directors in its definitive proxy statement filed with the SEC on March 17, 2011. You can find information about Progress Energy's executive officers and directors in its definitive proxy statement filed with the SEC on March 31, 2011. Additional information about Duke Energy's executive officers and directors and Progress Energy's executive officers and directors can be found in the above-referenced Registration Statement on Form S-4 when it becomes available. You can obtain free copies of these documents from Duke Energy and Progress Energy using the contact information above.

Executive and Senior Officers

William D. Johnson
Chairman, President and Chief Executive Officer
Progress Energy, Inc.

John R. McArthur
Executive Vice President, General Counsel and Corporate Secretary
Progress Energy, Inc.

Chief Compliance Officer
Progress Energy, Inc.
Progress Energy Carolinas, Inc.
Progress Energy Florida, Inc.

Mark F. Mulhern
Senior Vice President and Chief Financial Officer
Progress Energy, Inc.

Jeffrey J. Lyash
Executive Vice President – Energy Supply
Progress Energy, Inc.

Vincent M. Dolan
President and Chief Executive Officer
Progress Energy Florida, Inc.

Lloyd M. Yates
President and Chief Executive Officer
Progress Energy Carolinas, Inc.

Jeffrey A. Corbett
Senior Vice President – Energy Delivery
Progress Energy Carolinas, Inc.

Michael A. Lewis
Senior Vice President – Energy Delivery
Progress Energy Florida, Inc.

James Scarola
Senior Vice President and Chief Nuclear Officer
Progress Energy Carolinas, Inc.
Progress Energy Florida, Inc.

Paula J. Sims
Senior Vice President – Corporate Development and Improvement
Progress Energy Carolinas, Inc.
Progress Energy Florida, Inc.

FINANCIAL REPORT

FINANCIAL REPORT

The matters discussed throughout this Annual Report 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 we 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 Annual Report include, but are not limited to, "Management's Discussion and Analysis of Financial Condition and Results of Operations" including, but not limited to, statements under the following headings: a) "Merger" about the proposed merger between Progress Energy and Duke Energy Corporation and the impact 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 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;
- 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;
- our 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 us;
- our ability to maintain our 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 our filings with the SEC. 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 Progress Energy.

Management's Discussion and Analysis of Financial Condition and Results of Operations (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" for a discussion of the factors that may impact any such forward-looking statements made herein. As used in this report, Progress Energy, which includes the Parent and its regulated and nonregulated subsidiaries on a consolidated basis, is at times referred to as "we," "us" or "our."

MD&A includes financial information prepared in accordance with accounting principles generally accepted in the United States of America (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. Additionally, we may collectively refer to our electric utility subsidiaries, Progress Energy Carolinas (PEC) and Progress Energy Florida (PEF), as the "Utilities." MD&A should be read in conjunction with the Progress Energy Consolidated Financial Statements. Certain amounts for 2009 and 2008 have been reclassified to conform to the 2010 presentation.

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, Progress Energy Service Company, LLC (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 Corporation (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 continue as a wholly owned subsidiary of Duke Energy. Consummation of the Merger is subject to customary conditions, including, among other things, approval of the shareholders of each company, expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and receipt of all approvals, 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, the South Carolina Public Service Commission (SCPSC), the Florida Public Service Commission (FPSC), the Indiana Utility Regulatory Commission and the Ohio Public Utilities Commission.

See Note 25 for 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 2011 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 2011, except that we do not expect to issue a material amount of equity. Pursuant to the Merger Agreement, only limited equity issuances through certain employee benefit plans and stock option plans are permitted. 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.

The Parent's credit facility expires May 3, 2012, and the combined shelf registration statement for the Parent, PEC and PEF expires November 18, 2011. The timing and structure of refinancing the Parent's credit facility and filing the combined shelf registration statement with the SEC will be evaluated as more definitive timelines for the Merger and integration are developed (see "Future Liquidity and Capital Resources – Credit Facilities and Registration Statements" below).

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 14).

The companies are targeting for the Merger to close by the end of 2011. 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 on a pre-merger basis.

Strategy

We are an integrated energy company primarily focused on the end-use electricity markets. We own two electric utilities that operate in regulated retail utility markets in North Carolina, South Carolina and Florida and have access to attractive wholesale markets in the eastern United States. The Utilities have more than 22,000 megawatts (MW) of regulated electric generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities.

We have a strong track record of meeting our financial commitments. We have maintained liquidity and financial stability and sustained our dividend rate during the current economic downturn, and we believe that we have good prospects for growth once the economy begins to recover. In terms of our priorities for Progress Energy as a whole, we first focus on excelling in the fundamentals of our business. These fundamentals include safety, operational excellence, customer service, consistently achieving our financial objectives, maintaining constructive relations with regulators, political leaders and the general public as well as an internal focus on strong leadership that fully engages our workforce for high performance. In addition to excelling in these fundamentals, management has the following four focus areas for 2011:

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

IMPROVE NUCLEAR FLEET PERFORMANCE

We are implementing a comprehensive improvement plan designed to strengthen and align the performance of our 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.

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. We are gaining a clearer understanding of our cost drivers and of the dynamics shaping our near- and longer-term workforce planning needs. 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). During 2010, we held more than 200 Lean events, a 50 percent increase over the prior year. The process changes resulting from these events are improving our safety and operational performance, enhancing the productivity and engagement of our employees, managing our rising costs and, ultimately, increasing customer satisfaction.

BALANCED SOLUTION STRATEGY

Our balanced solution strategy is a portfolio of investments and initiatives to meet future customer needs and evolving public policies in a way that creates long-term value for our customers and shareholders. The strategy is focused on expanding the diversity of our resources, including energy efficiency, alternative energy and a state-of-the-art power system. Expenditures to achieve our balanced solution are anticipated to be recoverable under base rates or cost-recovery mechanisms implemented by our state jurisdictions. Updates on our implementation of this strategy are discussed below.

First, we are continuing to expand and enhance our demand-side management (DSM), energy-efficiency (EE) and energy-conservation programs. We have implemented customer energy-saving programs, provided customers with incentives for efficiency improvements and expanded our 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 are participating, along with nine other utilities across the nation, in Chevrolet's two-year demonstration and research program for its Volt electric vehicle. As a program participant, we will use 12 electric vehicles to conduct a variety of utility service roles. Additionally, we will gather data from driver surveys and charging stations and study the impact of the vehicles on the electric grid.

Second, we are actively engaged in a variety of alternative energy projects. We have executed contracts to purchase 311 MW of electricity generated from solar, biomass and municipal solid waste sources. 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 by 2012.

Third, we are pursuing numerous options to create a state-of-the-art power system. We are making a significant investment in smart grid technology with the initiatives partially funded by $200 million of federal matching infrastructure funds. Our strategy also includes advanced environmental controls on our coal-fired plants, and we have successfully completed the $2 billion of emission control installations planned for our coal fleets in North Carolina and Florida. Of our approximately 7,500 MW of coal-fired generation, we have scrubbed and installed emission control equipment on almost 5,000 MW. We are also moving forward with our previously announced coal-to-gas modernization strategy, which includes retiring our North Carolina coal-fired plants that do not have scrubbers (totaling approximately 1,500 MW) and replacing them with new combined-cycle natural gas plants. We expect to retire these coal-fired generating facilities no later than the end of 2014, and the new natural gas plants are expected to be placed in service in 2013 and 2014. 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. A reduced emissions profile puts us in a better position to comply with the more stringent environmental regulations anticipated in the future.

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 combined license (COL) application with the NRC for two additional reactors each at Shearon Harris Nuclear Plant (Harris) and at a greenfield site in Levy County, Florida (Levy).

We have focused on 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. PEF has entered into an engineering, procurement and construction (EPC) agreement and received two of the three key approvals needed for the proposed Levy units (with the issuance of the COL remaining). In light of a regulatory schedule shift and other factors, we have amended the EPC agreement and are deferring major construction on Levy until we receive the COL, expected in 2013. This decision will reduce the near-term price impact on customers and allows time for economic recovery and greater clarity on federal and state policies. Once we have received the COL, we will assess the project and determine the schedule.

INTEGRATION PLANNING AND TIMELY MERGER APPROVALS

We are in the early stages of integration planning for the Merger, and are also preparing for the various steps in the merger approval process. We believe our Continuous Business Excellence initiative will help us in the merger integration process. One important element of the initiative is getting a better understanding of the dynamics shaping near- and long-term workforce needs, which will be beneficial in integration planning. Integration planning efforts will also focus on savings from the fuel purchasing power and joint dispatch of generating plants of the combined companies. Maintaining constructive relations with regulators, public leaders and the general public is fundamental to our business, which will be critical for obtaining needed merger approvals in a timely manner.

MATTERS IMPACTING FUTURE RESULTS AND LIQUIDITY

The impact of favorable weather on the Utilities' revenues in 2010 offset the impacts of a continuing sluggish economy and cost pressures facing the utility industry. An improving national economy may lead to greater mobility for homeowners around the country and a return of migration to the Southeast region that is more consistent with our historical levels. However, the utility industry, as a whole, faces significant cost pressures and, in the near term, lower retail electricity sales. Current economic conditions and anticipated higher expenditures (including expenditures for environmental compliance, renewable energy standards compliance and new generation and transmission facilities) may subject us to an even higher level of scrutiny from regulators and lead to a more uncertain regulatory environment. Timely regulatory recovery of costs recoverable under the Utilities' pass-through clauses (such as fuel and environmental compliance) is important to maintaining appropriate levels of liquidity.

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.

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 after excluding 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.

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, 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[b]	**$600**	**$451**	**$(195)**	**$856**	**$2.95**
Year ended December 31, 2009					
Ongoing Earnings	$540	$460	$(154)	$846	$3.03
CVO mark-to-market	–	–	19	19	0.07
Impairment, net of tax[a]	–	–	(2)	(2)	(0.01)
Plant retirement charge, net of tax[a]	(17)	–	–	(17)	(0.06)
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[b]	$513	$460	$(216)	$757	$2.71
Year ended December 31, 2008					
Ongoing Earnings	$531	$383	$(138)	$776	$2.96
Valuation allowance and related net operating loss carry forward	–	–	(3)	(3)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	–	–	57	57	0.22
Net income (loss) attributable to controlling interests[b]	$531	$383	$(84)	$830	$3.17

[a] Calculated using assumed tax rate of 40 percent.
[b] 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 19).

Overview

FOR 2010 AS COMPARED TO 2009 AND 2009 AS COMPARED TO 2008

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 were:

- higher O&M expenses at the Utilities.

For the year ended December 31, 2009, our net income attributable to controlling interests was $757 million, or $2.71 per share, compared to net income attributable to controlling interests of $830 million, or $3.17 per share, for the same period in 2008. The decrease as compared to prior year was primarily due to:

- unfavorable impact of discontinued non-utility businesses (Ongoing Earnings adjustment);
- unfavorable net retail customer growth and usage at the Utilities;
- higher interest expense; and
- higher base depreciation and amortization at the Utilities.

Partially offsetting these items were:

- net impact of returns earned on higher levels of nuclear and environmental cost recovery clause (ECRC) assets at PEF;
- favorable impact of interim and limited base rate relief at PEF;
- depreciation and amortization expense recognized in 2008 at PEC related to North Carolina Clean Smokestacks Act (Clean Smokestacks Act) amortization expense and depreciation expense associated with the accelerated cost-recovery program for nuclear generating assets; and
- favorable weather at the Utilities.

Progress Energy Carolinas

PEC contributed net income available to parent totaling $600 million, $513 million and $531 million in 2010, 2009 and 2008, respectively. 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. The decrease in net income available to parent for 2009 as compared to 2008 was primarily due to unfavorable net retail customer growth and usage, coal plant retirement charges, higher base depreciation and amortization expense and a cumulative prior period adjustment related to certain employee life insurance benefits, partially offset by Clean Smokestacks Act amortization and depreciation expense associated with the accelerated cost-recovery program for nuclear generating assets recognized in 2008 and the favorable impact of weather.

PEC contributed Ongoing Earnings of $618 million, $540 million and $531 million for 2010, 2009 and 2008, respectively. The 2010 Ongoing Earnings adjustments to net income available to parent were due to PEC recording 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 adjustment, 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 2009 Ongoing Earnings adjustments to net income available to parent were due to PEC recording 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 charges to be representative of PEC's fundamental core earnings and excluded these charges in computing PEC's Ongoing Earnings. There were no Ongoing Earnings adjustments in 2008.

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 and fuel and other pass-through revenues. We 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. Clause-recoverable regulatory returns include the return on asset component of DSM, EE and renewable energy clause revenues. We have included the reconciliation and analysis that follows as a complement to the financial information we provide in accordance with GAAP.

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

(in millions)

Customer Class	2010	% Change	2009	% Change	2008
Residential	**$1,242**	10.1	$1,128	1.3	$1,113
Commercial	**726**	2.7	707	(1.4)	717
Industrial	**365**	2.5	356	(10.6)	398
Governmental	**65**	10.2	59	(3.3)	61
Unbilled	**10**	–	5	–	8
Total retail base revenues	**2,408**	6.8	2,255	(1.8)	2,297
Wholesale base revenues	**305**	(1.0)	308	0.3	307
Total Base Revenues	**2,713**	5.9	2,563	(1.6)	2,604
Clause-recoverable regulatory returns	**13**	44.4	9	–	–
Miscellaneous	**138**	21.1	114	11.8	102
Fuel and other pass-through revenues	**2,058**	–	1,941	–	1,723
Total operating revenues	**$4,922**	6.4	$4,627	4.5	$4,429

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 total Base Revenues were $2.563 billion and $2.604 billion for 2009 and 2008, respectively. The $41 million decrease in Base Revenues was due primarily to the $64 million unfavorable impact of net retail customer growth and usage, partially offset by the $23 million favorable impact of weather. 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 11,000 increase in the average number of customers for 2009 compared to 2008. The favorable impact of weather was driven by higher heating- and cooling-degree days than 2008 of 3 percent and 5 percent, respectively. Additionally, cooling-degree days were 6 percent higher than normal in 2009.

PEC's miscellaneous revenues increased $12 million in 2009 primarily due to higher transmission revenues.

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

(in millions of kWh)

Customer Class	2010	% Change	2009	% Change	2008
Residential	**19,108**	11.6	17,117	0.7	17,000
Commercial	**14,184**	4.0	13,639	(2.2)	13,941
Industrial	**10,665**	2.9	10,368	(9.0)	11,388
Governmental	**1,574**	5.1	1,497	2.1	1,466
Unbilled	**172**	–	360	–	(8)
Total retail kWh sales	**45,703**	6.3	42,981	(1.8)	43,787
Wholesale	**13,999**	0.2	13,966	(2.5)	14,329
Total kWh sales	**59,702**	4.8	56,947	(2.0)	58,116

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

The decrease in retail kWh sales in 2009 was primarily due to a decrease in average usage per retail customer due to economic conditions in the United States. PEC's industrial kWh sales decreased 9.0 percent from 2008, primarily due to reductions in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation as well as a downturn in the lumber and building materials segment as a result of declines in construction. Wholesale kWh sales decreased for 2009 primarily due to decreased excess generation sales resulting from unfavorable market dynamics.

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 $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 current year fuel costs 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.

Fuel and purchased power expenses totaled $1.909 billion for 2009, which represents a $217 million increase compared to 2008. This increase was primarily due to $248 million higher deferred fuel expense and the $86 million net impact of higher fuel costs driven by higher coal prices, partially offset by $128 million impact of lower system requirements. The increase in deferred fuel expense was primarily due to the implementation of higher fuel rates in North Carolina.

Operation and Maintenance

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 nitrogen oxides (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. 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. Certain O&M expense 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 $69 million compared to the same period in 2009.

O&M expense was $1.072 billion for 2009, which represents a $42 million increase compared to 2008. This increase was primarily due to coal plant retirement charges of $28 million, higher employee benefits expense of $12 million and storm costs of $9 million, partially offset by lower emission allowance expense of $13 million resulting from lower system requirements, changes in generation mix and sales of NOx allowances. As previously discussed, coal plant retirement charges 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 $29 million compared to the same period in 2008.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $479 million, $470 million and $518 million for 2010, 2009 and 2008, respectively. The $48 million decrease in 2009 compared to 2008 was primarily attributable to the $52 million of depreciation associated with the accelerated cost-recovery program for nuclear generating assets recognized in 2008 and the $15 million of Clean Smokestacks Act amortization recognized in 2008, partially offset by the $21 million impact of depreciable asset base increases. The North Carolina jurisdictional aggregate minimum amount of accelerated cost recovery has been met, and the South Carolina jurisdictional obligation was terminated by the SCPSC. PEC does not anticipate recording additional accelerated depreciation in the North Carolina jurisdiction, but will record depreciation over the remaining useful lives of the assets. In accordance with a regulatory order, PEC ceased to amortize Clean Smokestacks Act compliance costs, but will record depreciation over the useful lives of the assets.

Taxes Other Than on Income

Taxes other than on income was $218 million for 2010, which represents an $8 million increase compared to 2009. This increase was primarily due to an increase in gross receipts taxes due to higher operating revenues. Taxes other than on income was $210 million for 2009, which represents a $12 million increase compared to 2008. The increase was primarily due to an increase in gross receipts taxes due to higher operating revenues and higher property tax rates. Gross receipts 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 an expense of $8 million in 2010 and income of $5 million in 2008. The $8 million expense in 2010 was primarily due to the $7 million impairment of certain miscellaneous investments. The $5 million income in 2008 was primarily due to gain on land sales. 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 $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 is not material to 2009 or previously issued financial statements. Management determined that the adjustment should be an exclusion from PEC's 2009 Ongoing Earnings.

Total other income, net was $20 million for 2009, which represents a $23 million decrease compared to 2008. This decrease was primarily due to the previously discussed $16 million cumulative prior period adjustment related to certain employee life insurance benefits as well as lower interest income resulting from lower average eligible deferred fuel balances.

Total Interest Charges, Net

Total interest charges, net was $186 million, $195 million and $207 million for 2010, 2009 and 2008, respectively. The $9 million decrease in 2010 compared to 2009 was primarily due to $7 million favorable AFUDC debt related to increased construction project costs. The $12 million decrease in 2009 compared to 2008 was primarily due to lower interest rates on variable rate debt, partially offset by higher interest as a result of higher average debt outstanding.

Income Tax Expense

Income tax expense was $350 million, $277 million and $298 million in 2010, 2009 and 2008, respectively. The $73 million 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 change in the tax treatment of the Medicare Part D subsidy resulting from federal health care reform enacted earlier in 2010 (See Note 16). 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. The $21 million income tax expense decrease in 2009 compared to 2008 was primarily due to the impact of lower pre-tax income and the $5 million favorable tax benefit related to a deduction triggered by the transfer of previously funded amounts from nonqualified NDT funds to qualified NDT funds.

Progress Energy Florida

PEF contributed net income available to parent totaling $451 million, $460 million and $383 million in 2010, 2009 and 2008, respectively. The decrease in net income available to parent for 2010 as 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. The increase in net income available to parent for 2009 compared to 2008 was primarily due to higher clause-recoverable regulatory returns, the favorable impact of interim and limited base rate relief and the favorable impact of weather, partially offset by the unfavorable impact of retail customer growth and usage, higher base depreciation and amortization expense, and higher O&M.

PEF contributed Ongoing Earnings of $462 million, $460 million and $383 million in 2010, 2009 and 2008, respectively. The 2010 Ongoing Earnings adjustments to net income available to parent were due to PEF recording 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 or 2008.

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 and fuel and other pass-through revenues. We 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. Clause-recoverable regulatory returns include the revenues associated with the return on asset component of nuclear cost-recovery and ECRC revenues. We have included the reconciliation and analysis that follows as a complement to the financial information we provide in accordance with GAAP.

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

(in millions)

Customer Class	2010	% Change	2009	% Change	2008
Residential	**$1,045**	10.5	$946	5.9	$893
Commercial	**359**	5.6	340	3.7	328
Industrial	**75**	4.2	72	(5.3)	76
Governmental	**92**	5.7	87	6.1	82
Unbilled	**17**	–	9	–	(1)
Total retail base revenues	**1,588**	9.2	1,454	5.5	1,378
Wholesale base revenues	**160**	(22.7)	207	5.1	197
Total Base Revenues	**1,748**	5.2	1,661	5.5	1,575
Clause-recoverable regulatory returns	**173**	98.9	87	690.9	11
Miscellaneous	**216**	14.3	189	6.2	178
Fuel and other pass-through revenues	**3,117**	–	3,314	–	2,967
Total operating revenues	**$5,254**	0.1	$5,251	11.0	$4,731

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 Clean Air Interstate Rule (CAIR) projects into service in late 2009 and May 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 total Base Revenues were $1.661 billion and $1.575 billion for 2009 and 2008, respectively. The $86 million increase in Base Revenues was due primarily to the $79 million favorable impact of interim and limited base rate relief and the $36 million favorable impact of weather, partially offset by the $41 million unfavorable impact of retail customer growth and usage. The interim and limited base rate relief was approved by the FPSC effective July 1, 2009. Of the $79 million interim and limited base rate relief, $7 million related to interim rate relief, which was in effect for only 2009, and $72 million related to limited rate relief, which continued in accordance with the base rate proceeding with an annual revenue requirement of $132 million. The favorable impact of weather was primarily driven by 14 percent higher heating-degree days and 6 percent higher cooling-degree days than 2008. Heating-degree days were 4 percent lower than normal in 2009 and 16 percent lower than normal in 2008. In addition to lower average usage per customer, PEF's average number of customers for 2009, compared to 2008, decreased a net 8,000 customers.

PEF's clause-recoverable regulatory returns increased $76 million in 2009 primarily due to higher revenues related to nuclear cost recovery and ECRC assets of $61 million and $15 million, respectively. As a result of an FPSC regulatory order effective in January 2009, PEF is allowed to earn returns on certain costs related to nuclear construction.

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	**2010**	% Change	2009	% Change	2008
Residential	**20,524**	5.8	19,399	0.4	19,328
Commercial	**11,896**	0.1	11,884	(2.1)	12,139
Industrial	**3,219**	(2.0)	3,285	(13.2)	3,786
Governmental	**3,286**	0.9	3,256	(1.4)	3,302
Unbilled	**458**	–	131	–	(99)
Total retail kWh sales	**39,383**	3.8	37,955	(1.3)	38,456
Wholesale	**3,857**	0.6	3,835	(43.1)	6,734
Total kWh sales	**43,240**	3.5	41,790	(7.5)	45,190

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

Wholesale kWh sales have increased in 2010 primarily due to favorable 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 have decreased primarily due to a contract amendment as previously discussed.

Wholesale base revenues increased in 2009, despite decreased wholesale kWh sales in 2009, primarily due to committed capacity revenues. The wholesale kWh sales decreased primarily due to market conditions in which wholesale customers fulfilled a portion of their system requirements from other sources. Many of the new and amended capacity contracts entered into in 2008 expired by the end of 2009.

Retail base revenues increased in 2009, despite a decrease in kWh sales for the same period, primarily due to the impact of interim and limited base rate relief approved by the FPSC in 2009.

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 $2.591 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 Crystal River Unit No. 3 Nuclear Plant (CR3) outage was completed in 2009, partially offset by increased current year fuel and purchased power costs of $189 million and an increase in the recovery of deferred capacity costs of $167 million. The increased current year fuel and purchased power costs were primarily driven by higher system requirements resulting from favorable 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.

Fuel and purchased power expenses totaled $2.754 billion in 2009, which represents a $126 million increase compared to 2008. This increase was primarily due to higher deferred fuel expense of $467 million driven by the implementation of new fuel rates, partially offset by $164 million lower interchange costs, a decrease in the recovery of deferred capacity costs of $91 million and decreased 2009 fuel costs of $70 million, all resulting from lower system requirements.

Operation and Maintenance

O&M expense was $912 million in 2010, which represents a $73 million increase compared to 2009. O&M expense increased 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.

O&M expense was $839 million in 2009, which represents a $26 million increase compared to 2008. The increase was primarily due to $63 million higher ECRC and ECCR costs primarily due to an increase in current year rates for recovery of emission allowances, higher pension costs of $24 million and higher nuclear plant outage and maintenance costs of $14 million, partially offset by lower storm cost recovery of $66 million due to the surcharge that ended in July 2008 and the impact of a change in our vacation benefits policy of $11 million. The ECRC and ECCR expenses and replenishment of storm damage reserve are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. Pension costs were higher due to a $20 million pension credit in 2008. Substantially all of 2009's pension expense was deferred in accordance with an FPSC order. In aggregate, O&M expenses recoverable through base rates increased $25 million compared to the same period in 2008.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $426 million for 2010, which represents a $76 million decrease compared to 2009. Depreciation, amortization and accretion expense decreased primarily due to a reduction in the cost of removal component of amortization expense of $60 million in accordance with the base rate settlement agreement (See Note 7C), the lower depreciation rate impact of $43 million and other adjustments required in the base rate 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. In accordance with PEF's base rate settlement agreement, PEF will have the discretion to reduce the cost of removal component of amortization expense in 2011 and 2012, subject to limitations (See Note 7C).

Depreciation, amortization and accretion expense was $502 million for 2009, which represents an increase of $196 million compared to 2008, primarily due to higher nuclear cost-recovery amortization of $155 million. In aggregate, depreciation, amortization and accretion expenses recoverable through base rates and the ECRC increased $31 million compared to 2008, primarily due to depreciable asset base increases.

Taxes Other Than on Income

Taxes other than on income was $362 million for 2010, which represents a $15 million increase compared to 2009. This increase was primarily due to higher property taxes of $14 million resulting primarily from placing the repowered Bartow Plant in service in June 2009. Taxes other than on income was $347 million for 2009, which represents an increase of $38 million compared to 2008, primarily due to an increase in gross receipts and franchise taxes due to higher operating revenues. 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 an expense of $4 million and $7 million in 2010 and 2009, respectively, and income of $5 million in 2008. The $7 million expense in 2009 was primarily due to regulatory disallowance of fuel costs. The $5 million income in 2008 was primarily due to gain on land sales.

Total Other Income, Net

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 other income, net was $100 million for 2009, which represents a $6 million increase compared to 2008. This increase was primarily due to the $16 million of investment gains on certain employee benefit trusts resulting from improved market conditions, partially offset by $5 million lower interest income resulting from lower short-term investment balances and $4 million unfavorable AFUDC equity related to lower eligible construction project costs, primarily due to placing the repowered Bartow Plant into service in 2009.

Total Interest Charges, Net

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

Total interest charges, net was $231 million in 2009, which represents an increase of $23 million compared to 2008. The increase in interest charges was primarily due to higher interest as a result of higher average debt outstanding.

Income Tax Expense

Income tax expense was $276 million, $209 million and $181 million in 2010, 2009 and 2008, respectively. 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 change in the tax treatment of the Medicare Part D subsidy resulting from federal health care reform enacted earlier in 2010 (See Note 16). AFUDC equity is excluded from the calculation of income tax expense. As previously discussed, 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 in the tax treatment of the Medicare Part D subsidy is excluded in computing PEF's Ongoing Earnings.

The $28 million income tax expense increase in 2009 compared to 2008 was primarily due to the $40 million impact of higher pre-tax income compared to the prior year, partially offset by the $11 million impact of the favorable tax benefit related to a deduction triggered by the transfer of previously funded amounts from the nonqualified NDT fund to the qualified NDT fund.

Corporate and Other

The Corporate and Other segment primarily includes the operations of the Parent, PESC and other miscellaneous nonregulated businesses (Corporate and Other) 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)	**2010**	Change	2009	Change	2008
Other interest expense	**$(298)**	$(52)	$(246)	$(31)	$(215)
Other income tax benefit	**116**	19	97	6	91
Other expense	**(9)**	(4)	(5)	9	(14)
Ongoing Earnings	**(191)**	(37)	(154)	(16)	(138)
CVO mark-to-market	–	(19)	19	19	–
Impairment, net of tax	–	2	(2)	(2)	–
Valuation allowance and related net operating loss carry forward	–	–	–	3	(3)
Discontinued operations attributable to controlling interests, net of tax	**(4)**	75	(79)	(136)	57
Net loss attributable to controlling interests	**$(195)**	$21	$(216)	$(132)	$(84)

OTHER INTEREST EXPENSE

Other interest expense was $298 million, $246 million and $215 million for 2010, 2009 and 2008, respectively. The $52 million increase for 2010 compared to 2009 and the $31 million increase for 2009 compared to 2008 were primarily due to higher average debt outstanding at the Parent.

OTHER INCOME TAX BENEFIT

Other income tax benefit was $116 million, $97 million and $91 million for 2010, 2009 and 2008, respectively. The $19 million increase for 2010 compared to 2009 was primarily due to the favorable tax impact of higher pre-tax loss. The $6 million increase for 2009 compared to 2008 was primarily due to the favorable tax impact of higher pre-tax loss, partially offset by the unfavorable impact at the Corporate level resulting from the deductions taken by the Utilities related to NDT funds (See "Progress Energy Carolinas – Income Tax Expense" and "Progress Energy Florida – Income Tax Expense").

OTHER EXPENSE

Other expense was $9 million, $5 million and $14 million for 2010, 2009 and 2008, respectively. The $9 million change for 2009 compared to 2008 was primarily due to investment gains on certain employee benefit trusts resulting from improved financial market conditions in 2009.

ONGOING EARNINGS ADJUSTMENTS

CVO Mark-to-Market

Progress Energy issued 98.6 million contingent value obligations (CVOs) in connection with the acquisition of Florida Progress Corporation (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 15). The CVOs had a fair value of $15 million at December 31, 2010 and 2009 and $34 million at December 31, 2008. Progress Energy recorded unrealized gains of $19 million in 2009 to record the change in fair value of the CVOs, which had average unit prices of $0.16 at December 31, 2010 and 2009 and $0.35 at December 31, 2008. The unrealized 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.

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.

Valuation Allowance and Related Net Operating Loss Carry Forward

We previously recorded a deferred tax asset for a state net operating loss carry forward upon the sale of our nonregulated generating facilities and energy marketing and trading operations. In 2008, we recorded an additional $6 million deferred tax asset related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings. We also evaluated the total state net operating loss carry forward and recorded a partial valuation allowance of $9 million, which more than offset the change in estimate. Management does not consider net valuation allowances to be representative of our fundamental core 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 3 for additional information related to discontinued operations. We recognized $4 million and $79 million of loss from discontinued operations attributable to controlling interests, net of tax, for 2010 and 2009, respectively and $57 million of income from discontinued operations attributable to controlling interests, net of tax for 2008. Management does not consider operating results of discontinued operations to be representative of our fundamental core 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.

In 2008, we recognized $57 million of income from discontinued operations attributable to controlling interests, net of tax, which was comprised primarily of $49 million after-tax gains on sales of our coal terminals and docks in West Virginia and Kentucky and our remaining coal mining businesses.

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 prices (rates) 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 different 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 the Utilities meet the criteria to apply GAAP for regulated operations is a material assumption in the presentation and evaluation of our 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, cash flows and results of operations may be adversely impacted. See Note 7 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, 2010 and 2009, was $21.240 billion and $19.733 billion, respectively.

As discussed in Note 13, 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 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 our income 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.

Our total AROs at December 31, 2010, were $1.200 billion. 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 of Progress Energy's total AROs at December 31, 2010. 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 PEF filed with the FPSC in 2009 as part of PEF's base rate filing. As discussed in Note 4C, 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. 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 8, 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, 2010 and 2009, for the PEC and PEF reporting units were $1.922 billion and $1.733 billion, respectively.

As discussed in Note 1D, in October 2010 we prospectively changed our annual goodwill testing date from

April 1 to October 31 to better align our impairment testing procedures with the completion of our annual financial and strategic planning process. As a result, during 2010, we tested our goodwill for impairment as of October 31, 2010 and April 1, 2010, and concluded there was no impairment of the carrying value of the goodwill. If the estimated fair values of PEC and PEF on those dates had been lower by 10 percent, there still would be no impact on the reported value of their goodwill. In addition, based on the results of impairment tests performed in April 2009 and April 2008, we concluded there was no impairment of the carrying value of the goodwill in the prior periods presented in the consolidated financial statements. This change in accounting principle did not accelerate, delay, avoid, or cause a goodwill impairment charge.

We calculate the fair value of our utility reporting units by considering various factors, including valuation studies based primarily on income and market approaches. 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.

As an overall test of the reasonableness of the estimated fair values of the utility reporting units, we compared their combined fair value estimate to Progress Energy's market capitalization as of October 31, 2010 and April 1, 2010. The analyses confirmed that the fair values were reasonably representative of market views when applying a reasonable control premium to the market capitalization.

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. As a result of the Merger Agreement discussed within MD&A – "Introduction – Merger" and in Note 25, we considered whether an interim goodwill impairment test was necessary. Based upon reasonable allocations of the Merger consideration to PEC and PEF, we concluded their fair values exceeded their carrying values, and no interim impairment test was necessary.

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. At December 31, 2010 and 2009, amounts recorded as receivables on the Consolidated Balance Sheets related to unbilled revenues were $223 million and $193 million, respectively.

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 14, 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 16A, 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.

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 5.65% at December 31, 2010, from 6.00% at December 31, 2009, which will increase 2011 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 performed well in 2010 with returns of approximately 13%. That positive asset performance will result in decreased pension costs in 2011, all other factors remaining constant. In addition, contributions to pension plan assets in late 2010 and in 2011 will result in decreased pension costs in 2011 due to increased asset balances and resulting expected earnings on those assets, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2011 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2011 will be $70 million to $80 million, compared with $88 million recognized in 2010.

We have pension plan assets with a fair value of approximately $1.9 billion at December 31, 2010. Our expected rate of return on pension plan assets is 8.75%. 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 2009, we lowered the expected rate of return from the previously used 9.00%, due primarily to the uncertainties resulting from the severe capital market deterioration in 2008. A 25 basis point change in the expected rate of return for 2010 would have changed 2010 pension costs by approximately $4 million. For 2011, we have assumed an expected rate of return of 8.50%, which was reflected in the estimates of total 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 8.75% 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.

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.

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 with $4.7 billion of senior unsecured debt following its issuance of $500 million of senior unsecured debt on January 21, 2011. As a holding company, the Parent 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 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. In recent years, rather than paying dividends to the Parent, the Utilities, in certain cases, have retained their free cash flow to fund their capital expenditures. During 2010, PEC paid dividends of $100 million and PEF paid dividends of $50 million to the Parent. PEC and PEF expect to pay dividends to the Parent in 2011. 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 issuance, 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 2011. We do not expect to realize a material amount of proceeds from the sale of equity in 2011 (See "Financing Activities").

We have 24 financial institutions that support our combined $2.0 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, 2010, the Parent had no outstanding borrowings under its credit facility, no outstanding commercial paper and had issued $31 million of letters of credit, which were supported by the revolving credit facility. At December 31, 2010, PEC and PEF had no outstanding borrowings under their respective credit facilities and no outstanding commercial paper. Based on these outstanding amounts at December 31, 2010, there was a combined $1.969 billion available for additional borrowings.

At December 31, 2010, 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, 2010, the majority of the Utilities' open financial commodity hedges were in net mark-to-market liability positions. See Note 17A for additional information with regard to our commodity derivatives.

At December 31, 2010, 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, 2010, 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 17B for additional information with regard to our interest rate derivatives.

On July 21, 2010, the Wall Street Reform and Consumer Protection Act (H.R. 4173) was signed into law. Among other things, the law includes provisions related to the swaps and over-the-counter derivatives markets. Under the law, we expect to be exempt from mandatory clearing and exchange trading requirements for our commodity and interest rate hedges because we are an end user of these products. Capital and margin requirements for these hedges are expected to be determined as more detailed rules and regulations are published during 2011. At this time, we do not expect the law to have a material impact on our financial condition. 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.

Historical for 2010 as Compared to 2009 and 2009 as Compared to 2008

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, 2010, 2009 and 2008. Net cash provided by operating activities for the three years ended December 31, 2010, 2009 and 2008, was $2.537 billion, $2.271 billion and $1.218 billion, respectively.

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.

Net cash provided by operating activities for 2009 increased when compared with 2008. The $1.053 billion increase in operating cash flow was primarily due to a $290 million over-recovery of fuel in 2009 compared to a $333 under-recovery of fuel in 2008 due to higher fuel rates in 2009 and $340 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $200 million net refunds of cash collateral in 2009. These impacts were partially offset by $221 million of pension and other benefits contributions made 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, 2010, 2009 and 2008, was $2.400 billion, $2.532 billion and $2.541 billion, respectively.

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 $62 million increase in cash provided by other investing activities primarily due to the receipt of Nuclear Electric Insurance Limited (NEIL) insurance proceeds for repairs due to the CR3 extended outage (See "Future Liquidity and Capital Resources – Regulatory Matters and Recovery of Costs – CR3 Outage").

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $1 million in 2009 and $72 million in 2008, which are presented in other investing activities on the Consolidated Statements of Cash Flows, cash used in investing activities decreased by $80 million. The decrease in 2009 was primarily due to a $24 million decrease in gross property additions at the Utilities, primarily due to lower spending for environmental compliance projects and the completion of PEF's Bartow Plant repowering project in 2009; a $22 million decrease in nuclear fuel additions; and a $20 million decrease in net purchases of available-for-sale securities and other investments. Available-for-sale securities and other investments include marketable debt securities and investments held in nuclear decommissioning trusts.

During 2008, proceeds from sales of discontinued operations and other assets primarily included proceeds of $63 million from the sale of our coal terminals and docks and our remaining coal mining businesses (See Notes 3A and 3B).

FINANCING ACTIVITIES

Net cash (used) provided by financing activities for the three years ended December 31, 2010, 2009 and 2008, was $(251) million, $806 million and $1.248 billion, respectively. See Note 11 for details of debt and credit facilities.

Net cash used by financing activities increased by $1.057 billion for 2010 when compared to 2009. The increase was primarily due to the $1.687 billion reduction in proceeds from long-term debt issuances, net primarily due to the Parent's combined $1.700 billion issuances and PEC's $600 million issuance in 2009 compared to PEF's $600 million issuance of long-term debt in 2010; partially offset by the Parent's payments of $629 million on short-term debt with original maturities greater than 90 days in 2009.

Net cash provided by financing activities decreased by $442 million for 2009 when compared to 2008. The decrease is primarily due to a $1.082 billion increase in net payments on short-term debt with original maturities greater than 90 days, primarily driven by the Parent's repayment of prior-year borrowings under its revolving credit agreements (RCAs) and an $877 million net decrease in short-term indebtedness, primarily driven by commercial paper repayments; partially offset by a $491 million increase in proceeds from the issuance of common stock, primarily related to the Parent's January 2009 common stock offering; a $481 million increase in net proceeds from long-term debt issuances due to the Parent's combined $1.700 billion issuances and PEC's $600 million issuance in 2009 compared to PEF's $1.500 billion issuance and PEC's $325 million issuance in 2008; and a $477 million decrease in payments at maturity of long-term debt.

Our financing activities are described below.

2011

- On January 21, 2011, the Parent issued $500 million of 4.40% Senior Notes due 2021. We expect to use the net proceeds, along with available cash on hand, to retire at maturity the $700 million outstanding aggregate principal balance of our 7.10% Senior Notes due March 1, 2011.

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").
- On October 15, 2010, the Parent ratably reduced the size of its $1.130 billion credit facility to $500 million with the existing group of 15 financial institutions (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 Progress Energy Investor Plus Plan (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 Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the IPP. For 2009, the dividends paid on common stock were approximately $693 million.

2008

- On February 1, 2008, PEF paid at maturity $80 million of its 6.875% First Mortgage Bonds with available cash on hand and commercial paper borrowings.
- On March 12, 2008, PEC and PEF amended their RCAs with a syndication of financial institutions to extend the termination date by one year. The extensions were effective for both utilities on March 28, 2008. PEC's RCA was extended to June 28, 2011, and PEF's RCA was extended to March 28, 2011. These credit facilities were terminated on October 15, 2010 (See "Credit Facilities and Registration Statements").
- On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038. The proceeds were used to repay the maturity of PEC's $300 million 6.65% Medium-Term Notes, Series D, due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.
- On April 14, 2008, the Parent amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on May 2, 2008. The RCA is now scheduled to expire on May 3, 2012 (See "Credit Facilities and Registration Statements").
- On May 27, 2008, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity its remaining outstanding debt of $45 million of 6.46% Medium-Term Notes with available cash on hand.
- On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings, and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.
- On November 3, 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets. The borrowing was repaid during 2009.
- On November 18, 2008, the Parent, as a well-known seasoned issuer, PEC and PEF filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued (See "Credit Facilities and Registration Statements").
- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $132 million in proceeds from its IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 3.1 million shares for proceeds of approximately $131 million issued for the 401(k) and the IPP. For 2008, the dividends paid on common stock were approximately $642 million.

SHORT-TERM DEBT

At December 31, 2010, and at the end of each month during 2010, Progress Energy had no outstanding short-term debt.

Future Liquidity and Capital Resources

Please review "Safe Harbor for Forward-Looking Statements" 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, 2010, we have carried forward $836 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.

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 customer's 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.

On October 15, 2010, PEC and PEF entered into new three-year RCAs. The Parent's RCA will expire in May 2012, with the exception of approximately $22 million that will expire in May 2011 (See "Credit Facilities and Registration Statements"). In the event we enter into a new credit facility for the Parent, we cannot predict the terms, prices, duration or participants in such facility.

Progress Energy and its subsidiaries have approximately $12.642 billion in outstanding long-term debt, including the $505 million current portion at December 31, 2010. 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 Standard & Poor's Rating Services (S&P), the ratings of such utility's tax-exempt bonds would be below A-, most likely resulting in higher future interest rate resets. In the event of a two notch downgrade by Moody's Investor Services, Inc. (Moody's), PEC's tax-exempt bonds will continue to be rated at or above A3 while PEF's would be below A3, most 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 $300 million to $400 million directly to pension plan assets in 2011 (See Note 16).

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, 2009, have impacted the amount of collateral posted with counterparties. At December 31, 2010, we had posted approximately $164 million of cash collateral compared to $146 million of cash collateral posted at December 31, 2009. The majority of our financial hedge agreements will settle in 2011 and 2012. 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 17C, 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, 2010, the current portion of our long-term debt was $505 million. We expect to fund the Parent's $700 million of Senior Notes due March 1, 2011 with a combination of available cash on hand and net proceeds of $495 million from the Parent's issuance of $500 million of 4.40% Senior Notes on January 21, 2011. Accordingly, we classified $495 million of the Parent's $700 million Senior Notes due March 1, 2011 as long-term debt at December 31, 2010. We expect to fund PEF's $300 million current portion of long-term debt with a combination of cash from operations, commercial paper borrowings and/or long-term debt.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, including nuclear cost recovery, as discussed in Note 7 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 Clause

On June 23, 2010, the SCPSC approved PEC's request for a decrease in the fuel rate charged to its South Carolina ratepayers. The $17 million decrease, effective July 1, 2010, is driven by declining fuel prices.

On November 17, 2010, the NCUC approved PEC's request for a decrease in the fuel rate charged to its North Carolina ratepayers. The $170 million decrease, effective December 1, 2010, is also driven by declining fuel prices.

Also on November 17, 2010, the NCUC approved PEC's request for an increase in the DSM and EE rate charges to its North Carolina ratepayers. The $31 million increase was effective December 1, 2010.

PEC Other Matters

The NCUC has issued Certificates of Public Convenience and Necessity allowing PEC to proceed with plans to construct an approximately 600-MW generating facility at its Richmond County generation site projected to be in service by June 2011; 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.

PEF Base Rates

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 return on equity (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 Fuel Cost Recovery

On November 1, 2010, PEF filed a request with the FPSC to seek approval to decrease the total fuel cost-recovery by $205 million. This decrease is due to a decrease for the projected recovery through the Capacity Cost-Recovery Clause (CCRC) and for the projected recovery of fuel costs. The decrease in the CCRC is primarily due to the refund of a prior period over-recovery as a result of higher than expected sales in 2010 and lower anticipated costs associated with PEF's proposed Levy project in 2011 (See "Other Matters – Nuclear – Potential New Construction"). The decrease in the projected recovery of fuel costs is due to lower expected 2011 fuel costs, partially offset by an under-recovery of 2010 fuel costs. On November 2, 2010 and November 30, 2010, the FPSC approved PEF's CCRC residential rate and fuel rate, respectively.

PEF Nuclear Cost Recovery

PEF is allowed to recover prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balances on an annual basis through the CCRC. Such amounts will not be included in PEF'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 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.

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, PEF proposed and the FPSC approved collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. 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 2014.

On October 26, 2010, the FPSC approved PEF's annual nuclear cost-recovery filing with the FPSC to recover $164 million, which includes recovery of preconstruction, carrying and CCRC-recoverable O&M costs incurred or anticipated to be incurred during 2011, recovery of $60 million of the 2009 deferral in 2011, as well as the estimated true-up of 2010 costs associated with the Levy and CR3 uprate projects beginning with the first January 2011 billing cycle. Additionally, the FPSC approved the prudence of the 2009 costs associated with the Levy project. The final order was issued on February 2, 2011.

CR3 Outage

PEF maintains insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at CR3 through NEIL (See Note 4D). NEIL has confirmed that the CR3 delamination event is a covered accident. PEF is continuing to work with NEIL for recovery of applicable repair costs and associated replacement power costs.

The following table summarizes the CR3 replacement power and repair costs and recovery through December 31, 2010:

(in millions)	Replacement Power Costs	Repair Costs
Spent to date	$288	$150
NEIL proceeds received	(117)	(64)
Insurance receivable at December 31, 2010	(54)	(47)
Balance for recovery	$117	$39

PEF considers replacement power and capital costs not recoverable through insurance to be recoverable through its fuel cost-recovery clause or base rates. PEF accrued $171 million of replacement power cost reimbursements after the deductible period, which reduced the portion of the deferred fuel regulatory asset related to the extended CR3 outage to $117 million at December 31, 2010. Additional replacement power costs and repair and maintenance costs incurred until CR3 is returned to service could be material.

We cannot predict the outcome of this matter.

PEF Demand-Side Management Cost Recovery

On December 30, 2009, the FPSC ordered PEF and other Florida utilities to adopt DSM goals based on enhanced measures, which will result in significantly higher conservation goals. As subsequently revised by the FPSC, PEF's aggregate conservation goals over the next 10 years were: 1,134 Summer MW, 1,058 Winter MW, and 3,205 gigawatt-hours (GWh). On March 30, 2010, PEF filed a petition for approval of its proposed DSM plan and to authorize cost recovery through the ECCR. On September 14, 2010, the FPSC held an agenda conference to approve PEF's petition for the DSM plan. The FPSC ruled that while PEF's proposed DSM plan met the cumulative, 10-year DSM goals set by the FPSC, the plan did not meet the annual DSM goals. On October 4, 2010, the FPSC denied PEF's petition for the DSM plan, approved PEF's solar pilot programs, and required PEF to file a revised proposed DSM plan that meets the annual goals set by the FPSC. PEF filed a revised proposed DSM plan on November 29, 2010, which would result in 1,540 GWh of energy savings from 2011-2019, seven times more than PEF's historic goals. An agenda conference has been scheduled by the FPSC for April 5, 2011. We cannot predict the outcome of this matter.

PEF Other Matters

On November 1, 2010, the FPSC approved PEF's request to decrease the ECRC by $37 million, effective January 1, 2011. The decrease in the ECRC is primarily due to the 2010 base rate decision, which reduced the clean air project depreciation and return rates, and the refund of a prior period over-recovery as a result of higher than expected sales in 2010.

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 capital expenditures, including environmental compliance and other utility property additions, nuclear fuel expenditures and non-utility property additions, during 2010.

As shown in the table that follows, we expect the majority of our capital expenditures to be incurred at our regulated operations. We expect to fund our capital requirements primarily through a combination of cash from operations and long-term debt financings. In addition, we have $2.0 billion in credit facilities that support the issuance of commercial paper. Access to the commercial paper market provides additional liquidity to help meet our working capital requirements. AFUDC – borrowed funds represents the debt costs of capital funds necessary to finance the construction of new regulated plant assets.

	Actual	Forecasted		
(in millions)	**2010**	2011	2012	2013
Regulated capital expenditures	**$2,105**	$1,965	$1,820	$1,775
Nuclear fuel expenditures	**221**	205	225	240
AFUDC – borrowed funds	**(30)**	(30)	(30)	(20)
Other capital expenditures	**10**	30	30	30
Total before potential nuclear construction	**2,306**	2,170	2,045	2,025
Potential nuclear construction[a]	**104**	50–100	50–100	200–300
Total	**$2,410**	$2,220–2,270	$2,095–2,145	$2,225–2,325

[a] Expenditures for potential nuclear construction are net of AFUDC – borrowed funds.

Regulated capital expenditures for 2011, 2012 and 2013 in the previous table include approximately $30 million, $15 million and $25 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2011, 2012 and 2013 include $20 million, $15 million and $25 million, respectively, at PEC and $10 million at PEF for 2011. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance costs and related recovery of costs.

Potential nuclear construction expenditures, which are primarily for PEF's Levy project, include development, engineering, licensing, land acquisition and equipment.

Forecasted potential 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. 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. Additionally, in light of the schedule shifts in the Levy project, PEF may incur fees and charges related to the disposition of outstanding purchase orders on long lead time equipment, which could be material. In June 2010, PEF completed its long lead time equipment disposition analysis to minimize the impact associated with the schedule shift. As a result of the analysis, PEF will continue with selected components of the long lead time equipment. Work has been suspended on the remaining long lead time equipment items and PEF has been in suspension negotiations with the selected equipment vendors, which we anticipate concluding by the end of the first quarter of 2011. Potential nuclear construction expenditures are subject to cost-recovery provisions in the Utilities' respective jurisdictions.

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, 2010 and 2009, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2010 and 2009, we had no outstanding borrowings under our credit facilities. We are required to pay fees to maintain our credit facilities.

The following table summarizes our RCAs and available capacity at December 31:

(in millions)		Total	Outstanding	Reserved[a]	Available
2010					
Parent	**Five-year (expiring 5/3/12)[b]**	**$500**	**$–**	**$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**
2009					
Parent	Five-year (expiring 5/3/12)	$1,130	$–	$177	$953
PEC	Five-year (expiring 6/28/11)	450	–	–	450
PEF	Five-year (expiring 3/28/11)	450	–	–	450
Total credit facilities		$2,030	$–	$177	$1,853

[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, 2010 and 2009, the Parent had $31 million and $37 million, respectively, of letters of credit issued, which were supported by the RCA. Additionally, on December 31, 2009, the Parent had $140 million of outstanding commercial paper supported by the RCA.

[b] Approximately $22 million of the $500 million will expire May 3, 2011.

All of the revolving credit facilities were arranged through a syndication of financial institutions. See Note 11 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, 2010. We are currently in compliance and expect to continue to be in compliance with these covenants. See Note 11 for a discussion of the credit facilities' financial covenants. At December 31, 2010, the calculated ratios pursuant to the terms of the agreements, are as disclosed in Note 11.

The Parent, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement 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, stock purchase units, and trust preferred securities and guarantees. Both PEC and PEF have on file with the SEC shelf registration statements under which they may issue an unlimited number or amount of various long-term debt securities and preferred stock. The Parent's, PEC's and PEF's shelf registration statements filed with the SEC expire on November 18, 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, provided that adjusted net earnings are at least twice the annual interest requirement for bonds currently outstanding and to be outstanding. At December 31, 2010, PEC and PEF could issue up to approximately $6.8 billion and $2.7 billion of first mortgage bonds, respectively, based on property additions and retirements of previously issued first mortgage bonds. At December 31, 2010, PEC's and PEF's ratios of adjusted net earnings to annual interest requirement on outstanding first mortgage bonds were 5.6 times and 3.2 times, respectively.

CAPITALIZATION RATIOS

The following table shows each component of capitalization as a percentage of total capitalization at December 31, 2010 and 2009. 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.

	2010	2009
Total equity	**43.6%**	42.3%
Preferred stock	**0.4%**	0.4%
Total debt	**56.0%**	57.3%

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 customer's future energy needs.

As discussed in Note 17C, 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, 2010, we have issued $488 million of guarantees for future financial or performance assurance. 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, 2010, 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 17 and "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, 2010, 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 11)[a]	$12,699	$1,000	$1,780	$1,300	$8,619
Interest payments on long-term debt[b]	10,034	691	1,234	1,079	7,030
Capital lease obligations (See Note 22B)[c]	457	34	75	65	283
Operating leases (See Note 22B)[c]	1,415	37	154	182	1,042
Fuel and purchased power (See Note 22A)[d]	21,745	2,882	5,247	3,436	10,180
Other purchase obligations (See Note 22A)[e]	2,046	629	490	216	711
Minimum pension funding requirements[f]	568	126	267	153	22
Other postretirement benefits[g]	489	41	89	96	263
Uncertain tax positions[h]	–	–	–	–	–
Other commitments[i]	91	13	26	26	26
Total	$49,544	$5,453	$9,362	$6,553	$28,176

[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, 2010.

[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 $3.213 billion and an approximately $400 million Levy nuclear fuel fabrication contract. (See Note 22A and the other purchase obligations discussion following in (e)).

[e] Amounts exclude an EPC agreement that PEF entered into in December 2008 for two nuclear units planned for construction at Levy. As disclosed in "Other Matters – Nuclear – Potential New Construction," 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. We executed an amendment to the EPC agreement in 2010 due to the schedule shifts that will postpone major construction activities on the project until after the NRC issues the COL, which is expected to be in 2013, if the licensing schedule remains on track. Prior to the 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 the timing of when those obligations will be satisfied or the magnitude of any change. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF may incur fees and charges related to the disposition of outstanding purchase orders on long lead time equipment for the Levy nuclear project, which could be material. In June 2010, PEF completed its long lead time equipment disposition analysis to minimize the impact associated with the schedule shift. As a result of the analysis, PEF will continue with selected components of the long lead time equipment. Work has been 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. PEF has been in suspension negotiations with the selected equipment vendors, which we anticipate concluding by the end of the first quarter of 2011. In its April 30, 2010 nuclear cost-recovery filing, PEF included for rate-making purposes a point estimate of potential Levy disposition fees and charges of $50 million, subject to true-up. However, the amount of disposition fees and charges, if any, cannot be determined until suspension negotiations are completed. 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 $176 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 the total amounts of unrecognized tax benefits will decrease by up to approximately $60 million during the 12-month period ending December 31, 2011, due to expected settlements.

[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

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 7B and 7C. 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 United States Department of Energy (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, 2010, we have incurred $107 million of allowable, 50 percent reimbursable, smart grid project costs, and have submitted to the DOE requests for reimbursement of $47 million, of which we have received $34 million reimbursement.

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 reduce GHG emissions.

The North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (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 Florida Department of Environmental Protection (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," includes greater investment in energy efficiency, renewable energy and a state-of-the-art power system and 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) expanding our DSM and EE programs; (2) investing in the development of alternative energy resources for the future; and (3) operating 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 energy projects to pursue the generation of electricity from swine waste and other plant or animal sources, biomass, solar, hydrogen and landfill-gas technologies. Among our projects, we have executed contracts to purchase approximately 300 MW of electricity generated from biomass. This number includes 93 MW of biomass toward 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 7 MW of electricity generated from solar photovoltaic generation as part of the NC REPS. More than half of these projects are online and the remainder should be online by the end of 2011. Additionally, customers across our service territory have connected approximately 4 MW of solar photovoltaic energy systems to our grid. In June 2009, we expanded our solar energy strategy to include a range of new solar incentives and programs, which are expected 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 2014. 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 2014, 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, sulfur dioxide (SO_2), mercury and other pollutants have been reduced significantly at these sites.

In recent years, the federal government has authorized loan guarantee programs for innovative energy projects as well as newly constructed nuclear facilities. PEF decided not to pursue the loan guarantee program for the Levy project. However, this decision does not preclude PEF from revisiting the program at a later date if there are changes to the program. We cannot predict if PEF will pursue this program further.

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 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. We expect to complete repairs in March, and return the unit to service following successful completion of post-repair testing and start-up activities in April 2011. Nuclear safety remains our top priority, and our plans and actions will continue to reflect that commitment. A number of factors affect the return to service date, including regulatory reviews by the NRC and other agencies, emergent work, final engineering designs, testing, weather and other developments (See Note 7C).

PEC's nuclear units have operating licenses granted by the NRC that have been extended 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, if 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 with a decision expected in 2011.

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. The NRC estimates 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. 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, recent FPSC DSM goals and the resulting impact on ratepayers, 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 may incur fees and charges related to the disposition of outstanding purchase orders on long lead time equipment for the Levy nuclear project, which could be material. In June 2010, PEF completed its long lead time equipment disposition analysis to minimize the impact associated with the schedule shift. As a result of the analysis, PEF will continue with selected components of the long lead time equipment. Work has been suspended on the remaining long lead time equipment items and PEF has been in suspension negotiations with the selected equipment vendors, which we anticipate concluding by the end of the first quarter of 2011. In its April 30, 2010 nuclear cost-recovery filing, PEF included for rate-making purposes a point estimate of potential Levy disposition fees and charges of $50 million, subject to true-up. However, the amount of disposition fees and charges, if any, cannot be determined until suspension negotiations are completed. We cannot predict the outcome of this matter.

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 2010 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.

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.

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several 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 7 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.

In 2009, the EPA evaluated information about ash impoundment dams nationwide and developed a listing of 44 utility ash impoundment dams considered to have "high hazard potential," including two of PEC's ash impoundment dams. A "high hazard potential" rating is not related to the stability of those ash ponds but to the potential for harm should the impoundment dam fail. All of the dams at PEC's coal ash ponds have been subject to periodic third-party inspection for many years in accordance with prior applicable requirements. The EPA rated the 44 "high hazard potential" impoundments, as well as other impoundments, from "unsatisfactory" to "satisfactory" based on their structural integrity and associated documentation.

Only dams rated as "unsatisfactory" would be considered to pose an immediate safety threat. None of the facilities received an "unsatisfactory" rating from the EPA. In total, six of PEC's ash pond dams, including one "high hazard potential" impoundment, were rated as "poor" based on the contract inspector's desire to see additional documentation and evaluations of vegetation management and minor erosion control. Inspectors applied the same criteria to both active and inactive ash ponds, despite the fact that most of the inactive ash impoundments no longer hold water and do not pose a risk of breaching and spilling. PEC has completed several of the EPA's recommendations for the active ponds and other recommended actions are under way. Following evaluations and inspections, engineers have determined that one ash pond dam requires modifications to comply with current standards for an extra margin of safety for slope stability. Design and permitting efforts for that work have been initiated. PEC is working with the North Carolina Dam Safety program to evaluate the remaining recommendations. We do not expect mitigation of these issues to have a material impact on our results of operations.

As of January 1, 2010, dams at utility fossil-fired power plants in North Carolina, including dams for ash ponds, are subject to the North Carolina Dam Safety Act's applicable provisions, including state inspection. Those provisions are under the purview of the North Carolina Division of Land Resources. The division has completed its initial inspections of all of PEC's dams. No significant issues were found.

The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion residues, 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. On June 21, 2010, the EPA proposed two options for new rules to regulate coal combustion residues. The first option would create a comprehensive program of federally enforceable requirements for coal combustion residue management and disposal as hazardous waste. The other option would have the EPA set performance standards for coal combustion residues management facilities and regulate disposal of coal combustion residues as nonhazardous waste. 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 2011 or 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 AND WATER 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 expenses. Additionally, Congress may be considering legislation that would require reductions in air emissions of NOx, SO_2, carbon dioxide (CO_2) and mercury. Some proposals establish nationwide caps and emission rates over an extended period of time. This national multipollutant approach to air pollution control could involve significant capital costs that could be material to our financial position or results of operations. Control equipment installed pursuant to the provisions of CAIR, Clean Air Visibility Rule (CAVR) and mercury regulations, which are discussed below, may address some of the issues outlined previously. PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, CAVR and mercury regulation (see discussion of the court decisions that impacted the CAIR, the delisting determination and the Clean Air Mercury Rule [CAMR] below). The CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

Clean Smokestacks Act

In 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,000 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 plans to retire by the end of 2014, its remaining coal-fired generating facilities in North Carolina 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. We are continuing to evaluate various design, technology, generation and fuel options that could change expenditures required to 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 expenses that PEC incurs in connection with its environmental compliance control facilities.

Clean Air Interstate 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.

The air quality controls installed to comply with NOx 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 requirements for NOx for our North Carolina units at PEC. PEC and PEF met the 2009 phase I requirements for NOx and the 2010 phase I requirements of CAIR for NOx and SO_2 with a combination of emission reductions resulting from in-service emission control equipment and emission allowances. PEF's Crystal River Unit No. 4 (CR4) SO_2 and NOx emission control equipment was placed in service in May 2010 and PEF's Crystal River Unit No. 5 (CR5) SO_2 and NOx emission control equipment was placed in service in 2009.

In 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Court of Appeals) initially vacated the CAIR in its entirety and subsequently remanded the rule without vacating it for the EPA to conduct further proceedings consistent with the court's prior opinion. On August 2, 2010, the EPA published the proposed Transport Rule, which is the regulatory program that will replace the CAIR when finalized. The proposed Transport Rule contains new emissions trading programs for NOx and SO_2 emissions as well as more stringent overall emissions targets. The EPA plans to finalize the Transport Rule in the spring of 2011. Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe both PEC and PEF are well positioned to comply with the Transport Rule. The outcome of the EPA's rulemaking cannot be predicted. Because of the D.C. Court of Appeals' decision that remanded the CAIR, the current implementation of the CAIR continues to fulfill BART for NOx and SO_2 for BART-affected units under the CAVR. Should this determination change as the Transport Rule is promulgated, CAVR compliance eventually may require consideration of NOx and SO_2 emissions reductions in addition to particulate matter emissions reductions for BART-eligible units.

Under an agreement with the 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 required, PEF has advised the FDEP of developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated date as discussed in "Other Matters – Nuclear – Potential New Construction." 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.

Clean Air Mercury Rule

In 2008, the D.C. Court of Appeals vacated the CAMR. As a result, the EPA subsequently announced that it will develop a maximum achievable control technology (MACT) standard. The United States District Court for the District of Columbia has issued an order requiring the EPA to issue a final MACT standard for power plants by November 16, 2011. In addition, North Carolina adopted a state-specific requirement. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. We are currently evaluating the impact of these decisions. The outcome of this matter cannot be predicted.

Clean Air Visibility Rule

The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 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 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 7B, 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. Should this determination change as the Transport Rule is promulgated, CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions for BART-eligible units. 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. In August 2010, the FDEP amended 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. 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 CAVR, mercury regulation and related air quality regulations. The air quality controls installed to comply with NOx 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 requirements.

PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions have been placed in service. PEF's environmental compliance projects have also been placed 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 discussion previously regarding the vacating of the CAMR and remanding of the CAIR and its potential impact on CAVR). PEF's April 1, 2010 filing with the FPSC for true-up of final 2009 environmental costs included a review of the Integrated Clean Air Compliance Plan, which reconfirmed the efficacy of the recommended plan and included an estimated total project cost of approximately $1.1 billion to be spent through 2016, to plan, design, build and install pollution control equipment at the Anclote Plant, CR4 and CR5. The majority of the $1.1 billion estimated total project cost related to CR4 and CR5 projects, which have been placed in service. 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 final Transport Rule. 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

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 Transport Rule will be determined upon finalization of the rule. As a result of the decision remanding the CAIR, 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 a revised or new implementing rule for mercury will be determined upon finalization of the rule. 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. 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.

On January 7, 2010, the EPA announced a proposed revision to the primary ozone NAAQS. In addition, the EPA proposed a cumulative seasonal secondary standard. The EPA plans to finalize the revisions by July 29, 2011, and to designate nonattainment areas by August 2012. The proposed revisions are significantly more stringent than the current NAAQS. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of this matter cannot be predicted.

On January 25, 2010, the EPA announced a revision to the primary NAAQS for nitrogen dioxide. Historically, the standard for nitrogen dioxide has been an annual average. The EPA has retained the annual standard and added a new 1-hour NAAQS. In conjunction with proposing changes to the standard, the EPA is also requiring an increase in the coverage of the monitoring network, particularly near roadways where the highest concentrations are expected to occur due to traffic emissions. The EPA plans to designate nonattainment areas by January 2012. Currently, there are no monitors reporting violation of the new standard in PEC's or PEF's service territories, but the expanded monitoring network will provide additional data, which could result in additional nonattainment areas. The outcome of this matter cannot be predicted.

On June 22, 2010, the EPA published the final new 1-hour NAAQS for SO_2, which sets the limit at 75 parts per billion. The primary NAAQS on a 24-hour average basis and annual average will be eliminated under the new rule. The new 1-hour standard is a significant increase in the stringency of the standard and increases the risk of nonattainment, especially near uncontrolled coal-fired facilities. In addition, for the first time the EPA plans to use 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. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of this matter cannot be predicted.

Water Quality

1. General

As a result of the operation of certain pollution control equipment required to comply with 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 results of operations or financial position.

On September 15, 2009, the EPA concluded after a multi-year study of power plant wastewater discharges that current 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.

2. 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. Costs of compliance with a revised or new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our cost estimates to comply with the July 2004 rule were $60 million to $90 million. 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 14, 2011, and to issue a final decision by July 27, 2012. The outcome of this matter cannot be predicted.

OTHER ENVIRONMENTAL MATTERS

Climate Change

Growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other GHGs. In addition, the Obama administration 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. 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. On December 23, 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 will propose the standard by July 2011 and issue the final rule by May 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. We are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue.

The state of Florida's 2008 comprehensive energy legislation included a directive that the FDEP develop rules to establish a cap-and-trade program to regulate GHG emissions that would be presented to the legislature. The FDEP has studied GHG policy options and the potential economic impacts, but it has not developed a regulation for the consideration of the legislature. 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 the Utilities' 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.

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 adopted 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. On January 28, 2010, President Obama submitted a proposal to reduce the U.S. GHG emissions in the range of 17 percent below 2005 levels by 2020, subject to future congressional action.

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 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 emissions by March 31 of each year beginning in 2011 for year 2010 emissions. Because the rule builds on current emission-reporting requirements, compliance with the requirements is not expected to have a material impact on the Utilities.

On April 1, 2010, the EPA and the National Highway Transportation Safety Administration jointly announced the first regulation of GHG emissions from new vehicles. The EPA is regulating mobile source GHG emissions under Section 202 of the CAA, which according to the EPA also results in stationary sources, such as coal-fired power plants, being subject to regulation of GHG emissions under the CAA. On March 29, 2010, the EPA issued an interpretation that stationary source GHG emissions will be subject to regulation under the CAA beginning in January 2011. On May 13, 2010, 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, and it requires that the permitting requirements for GHG emissions from stationary sources begin on January 2, 2011. These developments require PEC and PEF to address GHG emissions in new air quality permits beginning in 2011. The impact of these developments cannot be predicted.

Synthetic Fuels Tax Credits

Historically, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Internal Revenue Code (the Code) (Section 29) and as redesignated effective 2006 as Section 45K of the Code (Section 45K) as discussed below. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. Qualifying synthetic fuels facilities entitled their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuels produced and sold by these plants. The synthetic fuels tax credit program expired at the end of 2007, and the synthetic fuels businesses were abandoned and reclassified to discontinued operations.

The amount of Section 29 tax credits that we were allowed to claim in any calendar year through December 31, 2005, was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits. Legislation enacted in 2005 redesignated Section 29 tax credits generated after January 1, 2006, as general business credits under Section 45K of the Code. The redesignation of Section 29 tax credits generated after January 1, 2006, as a Section 45K general business credit removed the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a one-year carry back period and a 20-year carry forward period.

Total Section 29/45K credits generated under the synthetic fuels tax credit program (including those generated by Florida Progress prior to our acquisition) were $1.891 billion, $1.055 billion of which has been used through December 31, 2010, to offset regular federal income tax liability and $836 million is being carried forward as deferred tax credits that do not expire.

See Note 22D for additional discussion related to our previous synthetic fuels operations.

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

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 17). 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 "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.

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 7 percent and 9 percent of consolidated debt had variable rates at December 31, 2010 and 2009, respectively.

Based on our variable rate long-term debt balances at December 31, 2010, a 100 basis point change in interest rates would result in an annual pre-tax interest expense change of approximately $9 million. We had no outstanding short-term debt at December 31, 2010.

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, 2010 and 2009, 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 2011 to 2015 and thereafter and the related fair value. Notional amounts are used to calculate the settlement amounts under the interest rate forward contracts. See Note 17 for more information on interest rate derivatives.

(dollars in millions) December 31, 2010	2011	2012	2013	2014	2015	Thereafter	Total	Fair Value December 31, 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 amount 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 0.30% at December 31, 2010.

During January 2011, Progress Energy terminated $300 million notional of forward starting swaps in conjunction with the issuance of $500 million of 4.40% Senior Notes.

At December 31, 2010, Progress Energy had $1.050 billion notional of open forward starting swaps.

(dollars in millions) December 31, 2009	2010	2011	2012	2013	2014	Thereafter	Total	Fair Value December 31, 2009
Fixed-rate long-term debt	$306	$1,000	$950	$825	$300	$7,864	$11,245	$12,126
Average interest rate	4.53%	6.96%	6.67%	4.96%	6.05%	6.13%	6.12%	
Variable-rate long-term debt	$100	–	–	–	–	$861	$961	$961
Average interest rate	0.73%	–	–	–	–	0.45%	0.48%	
Debt to affiliated trust[a]	–	–	–	–	–	$309	$309	$315
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate forward contracts[b]	$75	$150	$100	–	–	–	$325	$19
Average pay rate	3.48%	4.03%	4.07%	–	–	–	3.91%	
Average receive rate	[c]	[c]	[c]	–	–	–	[c]	

[a] Florida Progress Funding Corporation - Junior Subordinated Deferrable Interest Notes.
[b] Notional amount of 10-year forward starting swaps are categorized by mandatory cash settlement date.
[c] Rate is 3-month LIBOR, which was 0.25% at December 31, 2009.

At December 31, 2009, Progress Energy had $325 million notional of open forward starting swaps.

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, 2010 and December 31, 2009, the fair value of these funds was $1.571 billion and $1.367 billion, respectively. 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 13 for further information on the trust fund securities.

Contingent Value Obligations Market Value Risk

CVOs are recorded at fair value, and unrealized gains and losses from changes in fair value are recognized in earnings. At December 31, 2010 and December 31, 2009, the fair value of CVOs was $15 million. We perform sensitivity analyses to estimate our exposure to the market risk of the CVOs. The sensitivity analyses performed on the CVOs uses quoted 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, 2010 market price would result in a $2 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, 2010, substantially all derivative commodity instrument positions were subject to retail regulatory treatment.

See Note 17 for additional information with regard to our commodity contracts and use of economic and cash flow derivative financial instruments.

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, 2010. 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, 2010, 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, 2010, as stated in their report.

William D. Johnson
Chairman, President and Chief Executive Officer

Mark F. Mulhern
Senior Vice President and Chief Financial Officer

February 28, 2011

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, 2010, 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, 2010, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2010 of the Company, and our report dated February 28, 2011, expressed an unqualified opinion on those consolidated financial statements.

Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2011

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, 2010 and 2009, 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, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Progress Energy, Inc. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

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, 2010, 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, 2011, expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2011

CONSOLIDATED STATEMENTS OF INCOME

(in millions except per share data) Years ended December 31	**2010**	2009	2008
Operating revenues	**$10,190**	$9,885	$9,167
Operating expenses			
Fuel used in electric generation	**3,300**	3,752	3,021
Purchased power	**1,279**	911	1,299
Operation and maintenance	**2,027**	1,894	1,820
Depreciation, amortization and accretion	**920**	986	839
Taxes other than on income	**580**	557	508
Other	**30**	13	(3)
Total operating expenses	**8,136**	8,113	7,484
Operating income	**2,054**	1,772	1,683
Other income (expense)			
Interest income	**7**	14	24
Allowance for equity funds used during construction	**92**	124	122
Other, net	**–**	6	(17)
Total other income, net	**99**	144	129
Interest charges			
Interest charges	**779**	718	679
Allowance for borrowed funds used during construction	**(32)**	(39)	(40)
Total interest charges, net	**747**	679	639
Income from continuing operations before income tax	**1,406**	1,237	1,173
Income tax expense	**539**	397	395
Income from continuing operations	**867**	840	778
Discontinued operations, net of tax	**(4)**	(79)	58
Net income	**863**	761	836
Net income attributable to noncontrolling interests, net of tax	**(7)**	(4)	(6)
Net income attributable to controlling interests	**$856**	$757	$830
Average common shares outstanding – basic	**291**	279	262
Basic and diluted earnings per common share			
Income from continuing operations attributable to controlling interests, net of tax	**$2.96**	$2.99	$2.95
Discontinued operations attributable to controlling interests, net of tax	**(0.01)**	(0.28)	0.22
Net income attributable to controlling interests	**$2.95**	$2.71	$3.17
Dividends declared per common share	**$2.480**	$2.480	$2.465
Amounts attributable to controlling interests			
Income from continuing operations, net of tax	**$860**	$836	$773
Discontinued operations, net of tax	**(4)**	(79)	57
Net income attributable to controlling interests	**$856**	$757	$830

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(in millions)	**December 31, 2010**	December 31, 2009
ASSETS		
Utility plant		
Utility plant in service	**$29,708**	$28,353
Accumulated depreciation	**(11,567)**	(11,176)
Utility plant in service, net	**18,141**	17,177
Other utility plant, net	**220**	212
Construction work in progress	**2,205**	1,790
Nuclear fuel, net of amortization	**674**	554
Total utility plant, net	**21,240**	19,733
Current assets		
Cash and cash equivalents	**611**	725
Receivables, net	**1,033**	800
Inventory	**1,226**	1,325
Regulatory assets	**176**	142
Derivative collateral posted	**164**	146
Income taxes receivable	**52**	145
Prepayments and other current assets	**214**	248
Total current assets	**3,476**	3,531
Deferred debits and other assets		
Regulatory assets	**2,374**	2,179
Nuclear decommissioning trust funds	**1,571**	1,367
Miscellaneous other property and investments	**413**	438
Goodwill	**3,655**	3,655
Other assets and deferred debits	**325**	333
Total deferred debits and other assets	**8,338**	7,972
Total assets	**$33,054**	$31,236
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 293 million and 281 million shares issued and outstanding, respectively	**$7,343**	$6,873
Unearned ESOP shares (0 and 1 million shares, respectively)	**–**	(12)
Accumulated other comprehensive loss	**(125)**	(87)
Retained earnings	**2,805**	2,675
Total common stock equity	**10,023**	9,449
Noncontrolling interests	**4**	6
Total equity	**10,027**	9,455
Preferred stock of subsidiaries	**93**	93
Long-term debt, affiliate	**273**	272
Long-term debt, net	**11,864**	11,779
Total capitalization	**22,257**	21,599
Current liabilities		
Current portion of long-term debt	**505**	406
Short-term debt	**–**	140
Accounts payable	**994**	835
Interest accrued	**216**	206
Dividends declared	**184**	175
Customer deposits	**324**	300
Derivative liabilities	**259**	190
Accrued compensation and other benefits	**175**	167
Other current liabilities	**298**	239
Total current liabilities	**2,955**	2,658
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**1,696**	1,196
Accumulated deferred investment tax credits	**110**	117
Regulatory liabilities	**2,635**	2,510
Asset retirement obligations	**1,200**	1,170
Accrued pension and other benefits	**1,514**	1,339
Derivative liabilities	**278**	240
Other liabilities and deferred credits	**409**	407
Total deferred credits and other liabilities	**7,842**	6,979
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$33,054**	$31,236

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions) Years ended December 31	**2010**	2009	2008
Operating activities			
Net income	**$863**	$761	$836
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	**1,083**	1,135	957
Deferred income taxes and investment tax credits, net	**478**	220	411
Deferred fuel (credit) cost	**(2)**	290	(333)
Allowance for equity funds used during construction	**(92)**	(124)	(122)
Loss (gain) on sales of assets	**9**	2	(75)
Pension, postretirement and other employee benefits	**198**	135	71
Other adjustments to net income	**40**	134	64
Cash (used) provided by changes in operating assets and liabilities			
Receivables	**(200)**	26	233
Inventory	**98**	(99)	(237)
Derivative collateral posted	**(23)**	200	(340)
Other assets	**(1)**	14	(37)
Income taxes, net	**90**	(14)	(169)
Accounts payable	**125**	(26)	77
Accrued pension and other benefits	**(164)**	(285)	(39)
Other liabilities	**35**	(98)	(79)
Net cash provided by operating activities	**2,537**	2,271	1,218
Investing activities			
Gross property additions	**(2,221)**	(2,295)	(2,333)
Nuclear fuel additions	**(221)**	(200)	(222)
Purchases of available-for-sale securities and other investments	**(7,009)**	(2,350)	(1,590)
Proceeds from available-for-sale securities and other investments	**6,990**	2,314	1,534
Other investing activities	**61**	(1)	70
Net cash used by investing activities	**(2,400)**	(2,532)	(2,541)
Financing activities			
Issuance of common stock, net	**434**	623	132
Dividends paid on common stock	**(717)**	(693)	(642)
Payments of short-term debt with original maturities greater than 90 days	**–**	(629)	(176)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	**–**	–	629
Net (decrease) increase in short-term debt	**(140)**	(381)	496
Proceeds from issuance of long-term debt, net	**591**	2,278	1,797
Retirement of long-term debt	**(400)**	(400)	(877)
Cash distributions to noncontrolling interests	**(6)**	(6)	(85)
Other financing activities	**(13)**	14	(26)
Net cash (used) provided by financing activities	**(251)**	806	1,248
Net (decrease) increase in cash and cash equivalents	**(114)**	545	(75)
Cash and cash equivalents at beginning of year	**725**	180	255
Cash and cash equivalents at end of year	**$611**	$725	$180
Supplemental disclosures			
Cash paid for interest, net of amount capitalized	**$709**	$701	$612
Cash (received) paid for income taxes	**(56)**	87	152
Significant noncash transactions			
Accrued property additions	**313**	252	334
Asset retirement obligation additions and estimate revisions	**(36)**	(384)	14

See Notes to Consolidated Financial Statements.

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, 2007	**260**	**$6,028**	**$(37)**	**$(34)**	**$2,438**	**$84**	**$8,479**
Net income		–	–	–	830	6	836
Other comprehensive loss		–	–	(82)	–	–	(82)
Issuance of shares	4	132	–	–	–	–	132
Allocation of ESOP shares		13	12	–	–	–	25
Stock-based compensation expense		33	–	–	–	–	33
Dividends ($2.465 per share)		–	–	–	(646)	–	(646)
Distributions to noncontrolling interests		–	–	–	–	(85)	(85)
Contributions from noncontrolling interests		–	–	–	–	2	2
Other		–	–	–	–	(1)	(1)
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 (Note 2)		**–**	**–**	**–**	**–**	**(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**

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions) Years ended December 31	**2010**	2009	2008
Net income	**$863**	$761	$836
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax expense of $4, $4 and $2)	**6**	6	3
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $2, $3 and $1)	**3**	4	1
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $22, $(10) and $24)	**(34)**	16	(37)
Net unrecognized items for pension and other postretirement benefits (net of tax benefit (expense) of $8, $(1) and $29)	**(13)**	2	(49)
Other (net of tax benefit of $-, $- and $1)	**–**	1	–
Other comprehensive (loss) income	**(38)**	29	(82)
Comprehensive income	**825**	790	754
Comprehensive income attributable to noncontrolling interests, net of tax	**(7)**	(4)	(6)
Comprehensive income attributable to controlling interests	**$818**	$786	$748

See Notes to Consolidated 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." Additionally, we may collectively refer to our electric utility subsidiaries, Progress Energy Carolinas (PEC) and Progress Energy Florida (PEF), as the "Utilities."

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

The Parent is a public utility holding company headquartered in Raleigh, N.C. As such, we are 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.

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 is subject to the regulatory jurisdiction of the Florida Public Service Commission (FPSC), the NRC and the FERC.

See Note 19 for further information about our segments.

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. Significant 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 12 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 notes accompany and form an integral part of Progress Energy's consolidated financial statements.

Certain amounts for 2009 and 2008 have been reclassified to conform to the 2010 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.

In June 2009, the Financial Accounting Standards Board (FASB) issued new guidance that made significant changes to the model for determining who should consolidate a VIE and addressed how often this assessment should be performed. The guidance was effective for us on January 1, 2010 (See Note 2). As a result of the adoption, we deconsolidated two entities that qualify for low-income housing tax credits under Section 42 of the Internal Revenue Code (the Code) and recognized a $(2) million cumulative effect of change in accounting principle in 2010.

Progress Energy, through its subsidiary PEC, is the managing member, and primary beneficiary of, and consolidates an entity that qualifies for rehabilitation tax credits under Section 47 of the 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 2008 through 2010. 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 partnership as reflected in the Consolidated Balance Sheets at December 31:

(in millions)	**2010**	2009
Miscellaneous other property and investments	**$12**	$17
Other assets and deferred debits	**1**	1
Accounts payable	**5**	4

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 2008, 2009 and 2010. 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.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

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

FUEL COST DEFERRALS

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

EXCISE TAXES

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

The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income in the Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008 were $345 million, $333 million and $295 million, respectively.

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. Certain costs are capitalized in accordance with regulatory treatment. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property (including planned major maintenance activities), and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred, with the exception of nuclear outages at PEF. Pursuant to a regulatory order, PEF accrues for nuclear outage costs in advance of scheduled outages, which 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. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal or disposal costs that do not represent asset retirement obligations (AROs) are charged to a regulatory liability.

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

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 4A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization rates of utility assets (See Note 7).

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

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.

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 7A). The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

NUCLEAR COST DEFERRALS

PEF accounts for costs incurred in connection with the proposed nuclear expansion in Florida in accordance with FPSC regulations, which establish an alternative cost-recovery mechanism. PEF is allowed to accelerate the recovery of prudently incurred siting, preconstruction costs, AFUDC and incremental operation and maintenance expenses resulting from the siting, licensing, design and construction of a nuclear plant through PEF's capacity cost-recovery clause. 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. Intangible assets are amortized based on the economic benefit of their respective lives.

CHANGE IN ACCOUNTING POLICY REGARDING ANNUAL GOODWILL TESTING DATE

We perform our goodwill impairment tests for the PEC and PEF reporting units at least annually, and more often if events or changes in circumstances indicate it is more likely than not that their carrying values exceed their fair values. Since the adoption of Accounting Standards Codification (ASC) 350, Intangibles – Goodwill and Other, through April 1, 2010, we performed the annual impairment testing of goodwill using April 1 as the testing date. Our annual financial and strategic planning process, including the preparation of long-term cash flow projections, concludes in the fourth quarter of each year. Effective in October 2010, we changed our annual goodwill impairment testing date from April 1 to October 31 to better align our impairment testing procedures with the completion of our financial and strategic planning process. We believe the change is preferable since these long-term cash flow projections are a key component in performing our annual impairment tests of goodwill. During 2010, we tested our goodwill for impairment as of October 31, 2010 and April 1, 2010, and concluded there was no impairment of the carrying value of the goodwill. This change did not accelerate, delay, avoid, or cause a goodwill impairment charge. As it was impracticable to objectively determine operating and valuation estimates for periods prior to October 31, 2010, we have prospectively applied the change in the annual impairment testing date from October 31, 2010.

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

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

INCOME TAXES

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 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 Consolidated Statements of Cash Flows. See Note 17 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. 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. NEW ACCOUNTING STANDARDS

A. Consolidations

In June 2009, the FASB issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities." Subsequently, the FASB issued Accounting Standards Update (ASU) 2009-17, "Consolidations (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities," which codified SFAS No. 167 in the ASC. This guidance made significant changes to the model for determining who should consolidate a VIE, addressed how often this assessment should be performed, required all existing arrangements with VIEs to be evaluated, and was adopted through a cumulative effect of change in accounting principle adjustment. This guidance was effective for us on January 1, 2010. See Note 1C for information regarding our implementation of ASU 2009-17 and its impact on our financial position and results of operations.

B. Fair Value Measurement and Disclosures

In January 2010, the FASB issued ASU 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," which amends 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 disclosure but did not have an impact on our financial position or results of operations.

3. 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. The accompanying consolidated statements of income reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

On March 7, 2008, we sold coal terminals and docks in West Virginia and Kentucky for $71 million in gross cash proceeds. Proceeds from the sale were used for general corporate purposes. During the year ended December 31, 2008, we recorded an after-tax gain of $42 million on the sale of these assets. The accompanying consolidated financial statements reflect the operations 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.

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

(in millions)	**2010**	2009	2008
Revenues	**$–**	$–	$17
(Loss) earnings before income taxes and noncontrolling interest	**$(11)**	$(125)	$8
Income tax benefit, including tax credits	**5**	47	12
Earnings attributable to noncontrolling interests	**–**	–	(1)
Net (loss) earnings from discontinued operations attributable to controlling interests	**(6)**	(78)	19
Gain on disposal of discontinued operations, net of income tax expense of $7	**–**	–	42
(Loss) earnings from discontinued operations attributable to controlling interests	**$(6)**	$(78)	$61

B. Coal Mining Businesses

On March 7, 2008, we sold the remaining operations of subsidiaries engaged in the coal mining business for gross cash proceeds of $23 million. Proceeds from the sale were used for general corporate purposes. As a result of the sale, during the year ended December 31, 2008, we recorded an after-tax gain of $7 million on the sale of these assets. During the years ended December 31, 2010 and 2009, gains and losses related to post-closing adjustments and pre-divestiture contingencies were not material to our results of operations.

The accompanying consolidated financial statements reflect the coal mining businesses as discontinued operations. Results of discontinued operations for the coal mining businesses for the year ended December 31, 2008 were as follows:

(in millions)	2008
Revenues	$2
Loss before income taxes	$(13)
Income tax benefit	4
Net loss from discontinued operations	(9)
Gain on disposal of discontinued operations, net of income tax expense of $2	7
Loss from discontinued operations attributable to controlling interests	$(2)

C. 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, 2010, 2009 and 2008, gains and losses related to post-closing adjustments and pre-divestiture contingencies of other diversified businesses were not material to our results of operations.

4. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

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

(in millions)	Depreciable Lives	**2010**	2009
Production plant	3-41	**$16,042**	$15,477
Transmission plant	7-75	**3,530**	3,273
Distribution plant	13-67	**8,715**	8,376
General plant and other	5-35	**1,421**	1,227
Utility plant in service		**$29,708**	$28,353

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

As discussed in Note 7B, PEC intends to retire no later than December 31, 2014, 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. During the fourth quarter of 2010, Progress Energy reclassified, for all periods, the net carrying value of the four facilities from utility plant in service, net, to other utility plant, net, on the consolidated balance sheets, in accordance with ASC 980-360, Regulated Operations – Property, Plant and Equipment. At December 31, 2010 and 2009, the net carrying value of the four facilities included in other utility plant, net, totaled $172 million and $165 million, respectively. Consistent with current ratemaking treatment, PEC expects to include the four facilities' remaining net carrying value in rate base after retirement.

AFUDC represents the estimated costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant for certain projects in accordance with the regulatory provisions for each jurisdiction. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 9.2% in 2010, 2009 and 2008. The composite AFUDC rate for PEF's electric utility plant was 7.4%, effective beginning April 1, 2010, based on its authorized return on equity (ROE) approved in the base rate case (See Note 7C). Prior to April 1, 2010, the composite AFUDC rate for PEF's electric utility plant was 8.8%.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.0%, 2.4% and 2.3% in 2010, 2009 and 2008, respectively. The depreciation provisions related to utility plant were $635 million, $626 million and $578 million in 2010, 2009 and 2008, 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 4C), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization.

During 2010, PEF updated the depreciation rates which were 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 Open Access Transmission Tariff (OATT). The FERC filing requested depreciation rates be applied retroactively to January 1, 2010 whereby if approved, the depreciation rate changes will result in a reduction to the depreciation expense charged to PEF's OATT customers, beginning June 1, 2011.

Nuclear fuel, net of amortization at December 31, 2010 and 2009, was $674 million and $554 million, respectively. The amount not yet in service at December 31, 2010 and 2009, was $367 million and $308 million, respectively. 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 $132 million, $159 million and $145 million for the years ended December 31, 2010, 2009 and 2008, respectively. This amortization expense is included in fuel used in electric generation in the Consolidated Statements of Income.

PEF's construction work in progress related to certain nuclear projects has received regulatory treatment. At December 31, 2010, PEF had $519 million of accelerated recovery of construction work in process, of which $237 million was a component of a nuclear cost-recovery clause regulatory asset. At December 31, 2009, PEF had $451 million of accelerated recovery of construction work in process, of which $274 million was a component of a nuclear cost-recovery clause regulatory asset and $22 million was a component of a deferred fuel regulatory asset. See Note 7C 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 Consolidated 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
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**	**–**
2009					
PEC	Mayo	83.83%	$785	$282	$8
PEC	Harris	83.83%	3,207	1,651	28
PEC	Brunswick	81.67%	1,681	981	74
PEC	Roxboro Unit 4	87.06%	686	449	15
PEF	Crystal River Unit 3	91.78%	900	472	510
PEF	Intercession City Unit P11	66.67%	23	10	–

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 process for Crystal River Unit 3 Nuclear Plant (CR3) is not reduced by the accelerated recovery of qualifying project costs under the FPSC nuclear cost-recovery rule (see Note 7C).

C. Asset Retirement Obligations

At December 31, 2010 and 2009, our asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant, net of accumulated depreciation totaled $90 million and $132 million, respectively. The fair value of funds set aside in the Utilities' nuclear decommissioning trust (NDT) funds for the nuclear decommissioning liability totaled $1.571 billion and $1.367 billion at December 31, 2010 and 2009, respectively (See Notes 12 and 13). Net NDT unrealized gains are included in regulatory liabilities (See Note 7A).

Our nuclear decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2010, 2009 and 2008. 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. Expenses recognized 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, were $87 million, $141 million and $133 million in 2010, 2009 and 2008, respectively.

The Utilities recognize removal, nonirradiated decommissioning and dismantlement of fossil generation plant costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 7A). At December 31, such costs consisted of:

(in millions)	**2010**	2009
Removal costs	**$1,503**	$1,536
Nonirradiated decommissioning costs	**233**	211
Dismantlement costs	**121**	119
Non-ARO cost of removal	**$1,857**	$1,866

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 7D for information about the NRC operating licenses held by PEC. Based on updated cost estimates, in 2009 PEC reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $27 million and $390 million, respectively, resulting in no asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant at December 31, 2009.

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 (See Note 7C). 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. 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 7D 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. In addition, the wholesale accrual on PEF's reserves for nuclear decommissioning was suspended retroactive to January 2006, following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF received an updated fossil dismantlement study estimate in 2008, which PEF 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 $144 million and $143 million at December 31, 2010 and 2009, including amounts in the ARO liability for asbestos abatement, discussed below.

The Utilities have recognized ARO liabilities related to asbestos abatement costs. The ARO liabilities related to asbestos abatement costs were $53 million and $54 million at December 31, 2010 and 2009, respectively.

Additionally, the Utilities have recognized ARO liabilities related to landfill capping costs. The ARO liabilities related to landfill capping costs were $6 million and $7 million at December 31, 2010 and 2009, respectively.

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

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

(in millions)	
Asset retirement obligations at January 1, 2009	$1,471
Accretion expense	83
Revisions to prior estimates	(384)
Asset retirement obligations at December 31, 2009	1,170
Additions	**4**
Accretion expense	**65**
Revisions to prior estimates	**(39)**
Asset retirement obligations at December 31, 2010	**$1,200**

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 $28 million with respect to the primary coverage, $41 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, 2010, PEF has an outstanding claim with NEIL (See Notes 5 and 7C).

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 7C).

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.

5. RECEIVABLES

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

(in millions)	**2010**	2009
Trade accounts receivable	**$651**	$581
Unbilled accounts receivable	**223**	193
Other receivables	**75**	44
NEIL receivable (See Notes 4 and 7)	**119**	–
Allowance for doubtful receivables	**(35)**	(18)
Total receivables, net	**$1,033**	$800

6. INVENTORY

At December 31 inventory was comprised of:

(in millions)	**2010**	2009
Fuel for production	**$542**	$667
Materials and supplies	**676**	639
Emission allowances	**8**	18
Other	**–**	1
Total inventory	**$1,226**	$1,325

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits on the Consolidated Balance Sheets of $24 million at December 31, 2009, which was transferred to PEC in 2010 and is included in construction work in progress on the Consolidated Balance Sheet at December 31, 2010.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits on the Consolidated Balance Sheets of $33 million and $39 million, respectively, at December 31, 2010 and 2009.

7. REGULATORY MATTERS

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. 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:

(in millions)	**2010**	2009
Deferred fuel costs – current (Notes 7B and 7C)	**$169**	$105
Nuclear deferral (Notes 7C)	**7**	37
Total current regulatory assets	**176**	142
Deferred fuel cost – long-term	**–**	62
Nuclear deferral (Note 7C)[a]	**178**	239
Deferred impact of ARO (Note 4C)[b]	**122**	99
Income taxes recoverable through future rates[c]	**302**	264
Loss on reacquired debt[d]	**31**	35
Postretirement benefits (Note 16)[e]	**1,105**	945
Derivative mark-to-market adjustment (Note 17A)[f]	**505**	436
DSM / Energy-efficiency deferral (Note 7B)[g]	**57**	19
Other	**74**	80
Total long-term regulatory assets	**2,374**	2,179
Environmental (Note 7C)	**(45)**	(24)
Deferred energy conservation cost and other current regulatory liabilities	**(14)**	(3)
Total current regulatory liabilities	**(59)**	(27)
Non-ARO cost of removal (Note 4C)[b]	**(1,857)**	(1,866)
Deferred impact of ARO (Note 4C)[b]	**(143)**	(150)
Net nuclear decommissioning trust unrealized gains (Note 4C)[h]	**(421)**	(295)
Storm reserve (Note 7C)[i]	**(136)**	(136)
Other	**(78)**	(63)
Total long-term regulatory liabilities	**(2,635)**	(2,510)
Net regulatory liabilities	**$(144)**	$(216)

The recovery and amortization periods for these regulatory assets and (liabilities) at December 31, 2010, 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 16).

[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] 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.

[i] 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 rate cases in 1988, the NCUC and the SCPSC each authorized a ROE of 12.75 percent.

COST RECOVERY FILINGS

On November 17, 2010, the NCUC approved three separate PEC cost-recovery filings, all of which were effective December 1, 2010. The NCUC approved PEC's request for a $170 million decrease in the fuel rate charged to its North Carolina ratepayers, driven by declining fuel prices, which reduced residential electric bills by $5.60 per 1,000 kilowatt-hours (kWh) for fuel cost recovery. The NCUC approved PEC's request for a $31 million increase in the demand-side management (DSM) and EE rate charged to its North Carolina ratepayers, which increased the residential electric bills by $1.56 per 1,000 kWh for DSM and EE cost recovery. The NCUC approved PEC's request for a $2 million decrease for North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS), which decreased the residential electric bills by $0.07 per 1,000 kWh. The net impact of the three filings results in an average reduction in residential electric bills of 3.9 percent. At December 31, 2010, PEC's North Carolina deferred fuel and DSM / EE balances were $56 million and $49 million, respectively.

On June 23, 2010, the SCPSC approved PEC's request for a $17 million decrease in the fuel rate charged to its South Carolina ratepayers, driven by declining fuel prices. The decrease was effective July 1, 2010, and decreased residential electric bills by $2.73 per 1,000 kWh for fuel cost recovery. PEC also filed with the SCPSC for an increase in the DSM and EE rate effective July 1, 2010, which was approved on a provisional basis on June 30, 2010, pending review by the South Carolina Office of Regulatory Staff. The net impact of the two filings resulted in an average reduction in residential electric bills of 1.7 percent. We cannot predict the outcome of this matter. At December 31, 2010, PEC's South Carolina deferred fuel and DSM / EE balances were $15 million and $8 million, respectively.

OTHER MATTERS

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

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 December 1, 2009, PEC filed with the NCUC a plan to retire no later than December 31, 2017, 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 September 13, 2010, PEC filed its 15-year Integrated Resource Plan with the NCUC and SCPSC, which further accelerated the expected retirement schedule of the four coal-fired generating facilities to no later than December 31, 2014. The net carrying value of the four facilities at December 31, 2010, of $172 million is included in other utility plant, net on the Consolidated Balance Sheets. Consistent with ratemaking treatment, PEC will continue to depreciate these plants using the current depreciation lives and rates on file with the NCUC and the SCPSC until PEC completes and files a new depreciation study. The final recovery periods may change in connection with the regulators' determination of the rate recovery of the remaining net carrying value.

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.

The NCUC and the SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, through 2009. The North Carolina aggregate minimum and maximum amounts of cost recovery were $415 million and $585 million, respectively, with flexibility in the amount of annual depreciation recorded, from none to $150 million per year. Accelerated cost recovery of these assets resulted in additional depreciation expense of $52 million for the year ended December 31, 2008. PEC reached the minimum amount of $415 million of cost recovery by December 31, 2008, and no additional depreciation expense from accelerated cost recovery was subsequently recorded. As a result of the SCPSC's approval of a 2008 PEC petition, PEC will not be required to recognize the remaining $38 million of accelerated depreciation required to reach the minimum $115 million of cost recovery for the South Carolina jurisdiction, but will record depreciation over the useful lives of the assets. No additional depreciation expense from accelerated cost recovery for the South Carolina jurisdiction was recorded in 2008 or subsequent to the approval.

C. PEF Retail Rate Matters

BASE RATES

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, 2010, PEF recognized a $60 million reduction in amortization expense pursuant to the settlement agreement. PEF's applicable cost of removal reserve of $461 million is recorded as a regulatory liability on its December 31, 2010 Balance Sheet. 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, 2010, PEF's storm damage reserve was $136 million, the amount permitted by the settlement agreement.

On September 14, 2010, the FPSC approved a reduction to PEF's AFUDC rate, from 8.848 percent to 7.44 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 1, 2010, PEF filed a request with the FPSC to seek approval to decrease the total fuel-cost recovery by $205 million, reducing the residential rate by $6.64 per 1,000 kWh, or 5.2 percent effective January 1, 2011. This decrease is due to decreases of $5.14 per 1,000 kWh for the projected recovery through the Capacity Cost-Recovery Clause (CCRC) and of $1.50 per 1,000 kWh for the projected recovery of fuel costs. The decrease in the CCRC is primarily due to the refund of a prior period over-recovery as a result of higher than expected sales in 2010 and lower anticipated costs associated with PEF's proposed Levy Units No. 1 and No. 2 Nuclear Power Plants (Levy) in 2011 (See "Levy Nuclear"). The decrease in the projected recovery of fuel costs is due to an expectation of lower 2011 fuel costs and the continued recovery of incremental CR3 replacement power costs through insurance, partially offset by an under-recovery of 2010 fuel costs. On November 2, 2010 and November 30, 2010, the FPSC approved PEF's CCRC residential rate and fuel rate, respectively. 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"). At December 31, 2010, PEF's under-recovered deferred fuel balance was $98 million.

On October 25, 2010, the FPSC approved PEF's motion to establish a separate spin-off docket related to the outage and replacement fuel and power costs associated with the CR3 extended outage (See "CR3 Outage"). This docket will allow the FPSC to evaluate PEF's actions concerning the concrete delamination and review PEF's resulting costs associated with the CR3 extended outage. PEF intends to file a petition within 60 days following CR3's return to service; however, the FPSC has not yet established a case schedule. A hearing is expected later in 2011. We cannot predict the outcome of this matter.

NUCLEAR COST RECOVERY

Levy Nuclear

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 combined license (COL) application will not be authorized until the NRC issues the COL. Consequently, excavation and foundation preparation work anticipated in the initial schedule cannot begin until the COL is issued, resulting in a project shift of at least 20 months. Since then, regulatory and economic conditions identified in the 2010 nuclear cost-recovery filing have changed such that major construction activities on the Levy project are being postponed until after the NRC issues the COL, expected in 2013 if the current licensing schedule remains on track. 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; appropriate 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.

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. PEF will apply for the required license amendment for the third-stage design modification.

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 2014. At December 31, 2010, PEF's nuclear cost-recovery regulatory asset was $7 million and $178 million, classified as current and noncurrent, respectively.

On October 26, 2010, the FPSC approved PEF's annual nuclear cost-recovery filing to recover $164 million, which includes recovery of preconstruction, carrying and CCRC-recoverable operations and maintenance (O&M) costs incurred or anticipated to be incurred during 2011, recovery of $60 million of the 2009 deferral in 2011, as well as the estimated true-up of 2010 costs associated with the Levy and CR3 uprate projects. This resulted in a decrease in the nuclear cost-recovery charge of $1.46 per 1,000 kWh for residential customers, beginning with the first January 2011 billing cycle. The FPSC determined the costs associated with Levy were prudent and deferred a determination concerning the prudence of the 2009 CR3 uprate costs until the 2011 nuclear cost-recovery proceeding. The final order was issued on February 2, 2011.

CR3 OUTAGE

In September 2009, CR3 began an outage for normal refueling and maintenance as well as its uprate project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers 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. We expect to complete repairs in March, and return the unit to service following successful completion of post-repair testing and start-up activities in April 2011. A number of factors affect the return to service date, including regulatory reviews by the NRC and other agencies, emergent work, final engineering designs, testing, weather and other developments.

PEF maintains insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at CR3 through NEIL as discussed in Note 4D. PEF also maintains insurance coverage through an accidental property damage program, which provides insurance coverage with a $10 million deductible per claim. PEF notified NEIL of the claim related to the CR3 delamination event on October 15, 2009. NEIL has confirmed that the CR3 delamination event is a covered accident. PEF is continuing to work with NEIL for recovery of applicable repair costs and associated replacement power costs.

The following table summarizes the CR3 replacement power and repair costs and recovery through December 31, 2010:

(in millions)	Replacement Power Costs	Repair Costs
Spent to date	$288	$150
NEIL proceeds received	(117)	(64)
Insurance receivable at December 31, 2010	(54)	(47)
Balance for recovery	$117	$39

PEF considers replacement power and capital costs not recoverable through insurance to be recoverable through its fuel cost-recovery clause or base rates. PEF accrued $171 million of replacement power cost reimbursements after the deductible period, which reduced the portion of the deferred fuel regulatory asset related to the extended CR3 outage to $117 million at December 31, 2010. Additional replacement power costs and repair and maintenance costs incurred until CR3 is returned to service could be material. PEF requested, and the FPSC approved, the creation of a separate spin-off docket to review the prudence and costs related to the CR3 outage (See "Fuel Cost Recovery").

We cannot predict the outcome of this matter.

DEMAND-SIDE MANAGEMENT COST RECOVERY

On December 30, 2009, the FPSC ordered PEF and other Florida utilities to adopt DSM goals based on enhanced measures, which will result in significantly higher conservation goals. As subsequently revised by the FPSC, PEF's aggregate conservation goals over the next 10 years were: 1,134 Summer MW, 1,058 Winter MW, and 3,205 gigawatt-hours (GWh). On March 30, 2010, PEF filed a petition for approval of its proposed DSM plan and to authorize cost recovery through the Energy Conservation Cost Recovery Clause (ECCR). On September 14, 2010, the FPSC held an agenda conference to approve PEF's petition for the DSM plan. The FPSC ruled that while PEF's proposed DSM plan met the cumulative, 10-year DSM goals set by the FPSC, the plan did not meet the annual DSM goals. On October 4, 2010, the FPSC denied PEF's petition for the DSM plan, approved PEF's solar pilot programs, and required PEF to file a revised proposed DSM plan that meets the annual goals set by the FPSC. PEF filed a revised proposed DSM plan on November 29, 2010. An agenda conference has been scheduled by the FPSC for April 5, 2011. We cannot predict the outcome of this matter.

On November 1, 2010, the FPSC approved PEF's request to increase the ECCR residential rate by $0.29 per 1,000 kWh, or 0.2 percent of the total residential rate, effective January 1, 2011. The increase in the ECCR is primarily due to an increase in conservation program costs, including the costs associated with PEF's solar pilot, partially offset by a refund of a prior period over-recovery as a result of higher than expected sales in 2010.

OTHER MATTERS

On November 1, 2010, the FPSC approved PEF's request to decrease the Environmental Cost Recovery Clause (ECRC) by $37 million, reducing the residential rate by $1.02 per 1,000 kWh, or 0.8 percent, effective January 1, 2011. The decrease in the ECRC is primarily due to the 2010 base rate decision, which reduced the clean air project depreciation and return rates, and the refund of a prior period over-recovery as a result of higher than expected sales in 2010. At December 31, 2010, PEF's over-recovered deferred ECRC was $45 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, 2010, PEF has not recorded any amortization related to the 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. On December 18, 2008, PEF filed an application for a 20-year renewal from the NRC on the operating license for CR3, which would extend the operating license through 2036, if approved. PEF anticipates a decision from the NRC in 2011.

8. GOODWILL

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, 2010 and 2009, 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. As discussed in Note 1D, during 2010 we changed the annual testing date for our annual goodwill impairment tests from April 1 to October 31 of each year. As a result, we performed goodwill impairment tests as of April 1, 2010 and October 31, 2010, and concluded there was no impairment of the carrying value of the goodwill.

9. EQUITY

A. Common Stock

At December 31, 2010 and 2009, we had 500 million shares of common stock authorized under our charter, of which 293 million and 281 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, 2010, there were no significant restrictions on the use of retained earnings (See Note 11B and Note 25).

The following table presents information for our common stock issuances for the years ended December 31:

	2010		2009		2008	
(in millions)	**Shares**	**Net Proceeds**	Shares	Net Proceeds	Shares	Net Proceeds
Total issuances	**12.2**	**$434**	17.5	$623	3.7	$132
Issuances under an underwritten public offering[a]	**–**	**–**	14.4	523	–	–
Issuances through 401(k) and/or IPP	**11.2**	**431**	2.5	100	3.1	131

[a] The shares issued under an underwritten public offering were issued on January 12, 2009, at a public offering price of $37.50.

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 are used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes. At December 31, 2010, no ESOP suspense shares were outstanding and the ESOP acquisition loan was repaid.

There were 0.5 million ESOP suspense shares at December 31, 2009 with a fair value of $22 million. ESOP shares allocated to plan participants totaled 13.4 million and 13.0 million at December 31, 2010 and 2009, respectively. 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, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. 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 approximately $12 million, $12 million and $8 million for the years ended December 31, 2010, 2009 and 2008, respectively. At December 31, 2009, we had a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee was included in the determination of unearned ESOP common stock, which reduces common stock equity.

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 approximately $43 million, $41 million and $38 million for the years ended December 31, 2010, 2009 and 2008, 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.

In 2008, shares issued under the PSSP used only one performance measure. In 2009, the PSSP was redesigned. For 2009 and 2010, shares issued under the revised plan 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. Through December 31, 2010, we issued 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, 2010, 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. Through December 31, 2010, we issued 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, 2010, there were an immaterial number of RSUs outstanding.

The total fair value of RSUs vested during the years ended December 31, 2010, 2009 and 2008, was $24 million, $16 million and $9 million, respectively. No cash was expended to purchase stock to satisfy RSU plan obligations in 2010, 2009 and 2008. The RSUs vested during 2010 had a weighted-average grant date fair value of $43.58.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $27 million for the year ended December 31, 2010, with a recognized tax benefit of $11 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $37 million, with a recognized tax benefit of $14 million, and $34 million, with a recognized tax benefit of $13 million, for the years ended December 31, 2009 and 2008, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2010, unrecognized compensation cost related to nonvested other stock-based compensation plan awards totaled $25 million, which is expected to be recognized over a weighted-average period of 1.6 years.

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)	**2010**	2009	2008
Weighted-average common shares – basic	**290.7**	279.4	261.6
Net effect of dilutive stock-based compensation plans	**0.1**	0.1	0.1
Weighted-average shares – fully diluted	**290.8**	279.5	261.7

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, 1.5 million and 1.6 million stock options outstanding at December 31, 2010, 2009 and 2008, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive.

D. Accumulated Other Comprehensive Loss

Components of accumulated other comprehensive loss, net of tax, at December 31 were as follows:

(in millions)	**2010**	2009
Cash flow hedges	**$(63)**	$(35)
Pension and other postretirement benefits	**(62)**	(52)
Total accumulated other comprehensive loss	**$(125)**	$(87)

10. 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 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, 2010 and 2009, 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

11. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2010):

(in millions)		**2010**	2009
Parent			
Senior unsecured notes, maturing 2011-2039	6.64%	**$4,200**	$ 4,300
Unamortized premium and discount, net		**(6)**	(7)
Current portion of long-term debt		**(205)**	(100)
Long-term debt, net		**3,989**	4,193
PEC			
First mortgage bonds, maturing 2011-2038	5.60%	**2,525**	2,525
Pollution control obligations, maturing 2017-2024	0.89%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Miscellaneous notes	6.00%	**5**	21
Unamortized premium and discount, net		**(6)**	(6)
Current portion of long-term debt		**–**	(6)
Long-term debt, net		**3,693**	3,703
PEF			
First mortgage bonds, maturing 2011-2040	5.82%	**4,100**	3,800
Pollution control obligations, maturing 2018-2027	0.52%	**241**	241
Medium-term notes, maturing 2028	6.75%	**150**	150
Unamortized premium and discount, net		**(9)**	(8)
Current portion of long-term debt		**(300)**	(300)
Long-term debt, net		**4,182**	3,883
Progress Energy consolidated long-term debt, net		**$11,864**	$11,779
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**$309**	$ 309
Unamortized premium and discount, net		**(36)**	(37)
Long-term debt, affiliate		**$273**	$ 272

On January 21, 2011, the Parent issued $500 million of 4.40% Senior Notes due 2021. We expect to use net proceeds of $495 million, along with available cash on hand, to retire at maturity 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 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.

At December 31, 2010 and 2009, we had committed lines of credit used to support our commercial paper and other short-term borrowings. At December 31, 2010 and December 31, 2009, 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
2010					
Parent	**Five-year (expiring 5/3/12)[b]**	**$500**	**$–**	**$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**
2009					
Parent	Five-year (expiring 5/3/12)	$1,130	$–	$177	$953
PEC	Five-year (expiring 6/28/11)	450	–	–	450
PEF	Five-year (expiring 3/28/11)	450	–	–	450
Total credit facilities		$2,030	$–	$177	$1,853

[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, 2010 and 2009, the Parent had $31 million and $37 million, respectively, of letters of credit issued, which were supported by the RCA. Additionally, on December 31, 2009, the Parent had $140 million of outstanding commercial paper supported by the RCA.

[b] Approximately $22 million of the $500 million will expire May 3, 2011.

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 on June 28, 2011 and March 28, 2011, respectively. Both $450 million RCAs were terminated effective October 15, 2010. Fees and interest rates under the new RCAs are to be determined based upon the respective credit ratings of PEC's and PEF's long-term unsecured senior noncredit-enhanced debt, as rated by Moody's Investor Services, Inc. (Moody's) and Standard and Poor's Rating Services (S&P). The RCAs do not include material adverse change representations for borrowings or financial covenants for interest coverage. See "Covenants and Default Provisions" for additional provisions related to the RCAs.

Also on October 15, 2010, the Parent ratably reduced the size of its $1.130 billion credit facility to $500 million with the existing group of 15 financial institutions. As a result of the changes made on October 15, 2010, our combined credit commitments total $2.000 billion, supported by 24 financial institutions.

The following table summarizes short-term debt comprised of outstanding commercial paper, and related weighted-average interest rates at December 31:

(in millions)	**2010**		2009	
Parent	–%	$–	0.49%	$140
PEC	–	–	–	–
PEF	–	–	–	–
Total	–%	$–	0.49 %	$140

Long-term debt maturities during the next five years are as follows:

(in millions)	
2011	$1,000
2012	950
2013	830
2014	300
2015	1,000

B. Covenants and Default Provisions

FINANCIAL COVENANTS

The Parent's, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2010, the maximum and calculated ratios, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[a]
Parent	68%	56%
PEC	65%	42%
PEF	65%	49%

[a] Indebtedness as defined by the credit agreement includes certain letters of credit and guarantees not recorded on the Consolidated Balance Sheets.

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of the following thresholds: $50 million for the Parent and $35 million each for PEC and PEF. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of their respective cross-default threshold, the lenders of that credit facility could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. The Parent's cross-default provision can be triggered by the Parent and its significant subsidiaries, as defined in the credit agreement. PEC's and PEF's cross-default provisions can be triggered only by defaults of indebtedness by PEC and its subsidiaries and PEF, respectively, not 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 long-term debt. Following payment of the Parent's $700 million March 1, 2011 maturity, $4.000 billion in long-term debt could be subject to acceleration provisions. 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, 2010, the Parent had no shares of preferred stock outstanding. See Note 25 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'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, 2010, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2010, PEC's common stock equity was approximately 58.0 percent of total capitalization. At December 31, 2010, none of PEC's cash dividends or distributions on common stock was restricted.

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, 2010, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2010, PEF's common stock equity was approximately 53.7 percent of total capitalization. At December 31, 2010, none of PEF's cash dividends or distributions on common stock was restricted.

C. Collateralized Obligations

PEC's and PEF's first mortgage bonds are collateralized by their respective mortgage indentures. Each mortgage constitutes a first lien on substantially all of the fixed properties of the respective company, subject to certain permitted encumbrances and exceptions. Each mortgage also constitutes a lien on subsequently acquired property. At December 31, 2010, PEC and PEF had a total of $3.194 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 mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

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

E. Hedging Activities

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

12. INVESTMENTS

A. Investments

At December 31, 2010 and 2009, we had investments in various debt and equity securities, cost investments, company-owned life insurance and investments held in trust funds as follows:

(in millions)	**2010**	2009
Nuclear decommissioning trust (See Notes 4C and 13)	**$1,571**	$1,367
Equity method investments[a]	**16**	18
Cost investments[b]	**5**	5
Company-owned life insurance[c]	**46**	45
Benefit investment trusts[d]	**175**	191
Total	**$1,813**	$1,626

[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 in 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 in 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 in the Consolidated Balance Sheets.

[d] Benefit investment trusts are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2010 and 2009, $166 million and $152 million, respectively, of investments in company-owned life insurance were held in Progress Energy's trusts.

B. Impairment of Investments

We evaluate declines in value of investments under the criteria of GAAP. Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in long-term regulatory 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 13 for additional information. There were no material other-than-temporary impairments in 2010, 2009 or 2008.

13. FAIR VALUE DISCLOSURES

A. Debt and Investments

DEBT

The carrying amount of our long-term debt, including current maturities, was $12.642 billion and $12.457 billion at December 31, 2010 and 2009, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $14.0 billion and $13.4 billion at December 31, 2010 and 2009, 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 4C). 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
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**
2009			
Common stock equity	$839	$22	$301
Preferred stock and other equity	16	–	5
Corporate debt	71	1	5
U.S. state and municipal debt	118	2	3
U.S. and foreign government debt	197	1	8
Money market funds and other	161	–	–
Total	$1,402	$26	$322

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 2010 and 2009 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, 2010 and 2009.

The aggregate fair value of investments that related to the December 31, 2010 and 2009 unrealized losses was $195 million and $209 million, respectively.

At December 31, 2010, the fair value of our available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$27
Due after one through five years	223
Due after five through 10 years	126
Due after 10 years	117
Total	$493

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)	2010	2009	2008
Proceeds	**$6,747**	$2,207	$1,316
Realized gains	**21**	26	29
Realized losses	**27**	87	86

Proceeds were primarily related to NDT funds. 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, 2010 and 2009, our other securities had no investments in a continuous loss position for greater than 12 months.

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 financial assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2010 and 2009. 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.

(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 funds 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 derivatives	–	15	–	15
Total liabilities	$–	$512	$36	$548

(in millions)	Level 1	Level 2	Level 3	Total
2009				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$839	$–	$–	$839
Preferred stock and other equity	16	–	–	16
Corporate debt	–	71	–	71
U.S. state and municipal debt	–	117	–	117
U.S. and foreign government debt	62	128	–	190
Money market funds and other	1	133	–	134
Total nuclear decommissioning trust funds	918	449	–	1,367
Derivatives				
Commodity forward contracts	–	20	–	20
Interest rate contracts	–	19	–	19
Other marketable securities				
U.S. state and municipal debt	–	1	–	1
U.S. and foreign government debt	–	7	–	7
Money market funds and other	16	27	–	43
Total assets	$934	$523	$–	$1,457
Liabilities				
Derivatives				
Commodity forward contracts	$–	$386	$39	$425
Contingent value obligations derivatives	–	15	–	15
Total liabilities	$–	$401	$39	$440

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 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 17 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.

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

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 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 or 2 during the period other than those reflected in the Level 3 reconciliations. Transfers into and out of each level are measured at the end of the reporting period.

A reconciliation of changes in the fair value of our commodity derivatives, net classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

(in millions)	**2010**	2009	2008
Derivatives, net at beginning of period	**$39**	$41	$(26)
Total losses (gains), realized and unrealized deferred as regulatory assets and liabilities, net	**44**	13	102
Transfers (out) in of Level 3, net	**(47)**	(15)	(35)
Derivatives, net at end of period	**$36**	$39	$41

Substantially all unrealized gains and losses on derivatives are deferred as regulatory liabilities or assets consistent with ratemaking treatment. There were no Level 3 purchases, sales, issuances or settlements during the period.

14. 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.

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

(in millions)	**2010**	2009
Deferred income tax assets		
ARO liability	**$107**	$127
Derivative instruments	**204**	159
Income taxes refundable through future rates	**271**	225
Pension and other postretirement benefits	**447**	508
Other	**394**	374
Tax credit carry forwards	**839**	712
Net operating loss carry forwards	**105**	66
Valuation allowance	**(60)**	(55)
Total deferred income tax assets	**2,307**	2,116
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(2,439)**	(1,889)
Income taxes recoverable through future rates	**(875)**	(782)
Other	**(386)**	(338)
Total deferred income tax liabilities	**(3,700)**	(3,009)
Total net deferred income tax liabilities	**$(1,393)**	$(893)

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

(in millions)	2010	2009
Current deferred income tax assets, included in prepayments and other current assets	**$156**	$168
Noncurrent deferred income tax assets, included in other assets and deferred debits	**34**	37
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(1,583)**	(1,098)
Total net deferred income tax liabilities	**$(1,393)**	$(893)

At December 31, 2010, we had the following tax credit and net operating loss carry forwards:

- $836 million of federal alternative minimum tax credits that do not expire.
- $5 million of state income tax credits that will expire during 2013.
- $105 million of gross federal net operating loss carry forwards that will expire during 2030.
- $1.6 billion of gross state net operating loss carry forwards that will expire during the period 2011 through 2030.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We had a net increase of $5 million in our valuation allowances during 2010.

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 Corporation (Duke Energy) (See Note 25), 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:

	2010	2009	2008
Effective income tax rate	**38.3%**	32.1%	33.7%
State income taxes, net of federal benefit	**(4.3)**	(3.7)	(3.8)
Investment tax credit amortization	**0.5**	0.8	1.0
Employee stock ownership plan dividends	**0.9**	1.0	1.0
Domestic manufacturing deduction	–	0.8	0.3
AFUDC equity	**1.4**	2.2	2.5
Other differences, net	**(1.8)**	1.8	0.3
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

(in millions)	2010	2009	2008
Current			
Federal	**$(46)**	$227	$38
State	**(13)**	41	12
Total current income tax expense (benefit)	**(59)**	268	50
Deferred			
Federal	**542**	114	305
State	**100**	25	49
Total deferred income tax expense	**642**	139	354
Investment tax credit	**(7)**	(10)	(12)
Net operating loss carry forward	**(37)**	–	(6)
Beginning-of-the-year valuation allowance change	–	–	9
Total income tax expense	**$539**	$397	$395

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

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

- Taxes related to discontinued operations recorded net of tax for 2010, 2009 and 2008, which are presented separately in Notes 3A through 3C.

- Taxes related to other comprehensive income recorded net of tax for 2010, 2009 and 2008, which are presented separately in 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 2009 and 2008.

At December 31, 2010, 2009, and 2008, our liability for unrecognized tax benefits was $176 million, $160 million, and $104 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $8 million, $9 million, and $8 million, respectively, at December 31, 2010, 2009, and 2008. The following table presents the changes to unrecognized tax benefits during the years ended December 31:

(in millions)	**2010**	2009	2008
Unrecognized tax benefits at beginning of period	**$160**	$104	$93
Gross amounts of increases as a result of tax positions taken in a prior period	**10**	11	17
Gross amounts of decreases as a result of tax positions taken in a prior period	**(4)**	(3)	(11)
Gross amounts of increases as a result of tax positions taken in the current period	**14**	52	8
Gross amounts of decreases as a result of tax positions taken in the current period	**(4)**	(4)	(2)
Amounts of net increases relating to settlements with taxing authorities	**–**	–	1
Reduction as a result of a lapse of the applicable statute of limitations	**–**	–	(2)
Unrecognized tax benefits at end of period	**$176**	$160	$104

We file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Generally our open federal tax years are from 2004 forward, and our open state tax years in our major jurisdictions are from 2003 or 2004 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when the review will be completed. Although the timing for completion of the IRS review is uncertain, it is reasonably possible that unrecognized tax benefits will decrease by up to approximately $60 million during the 12-month period ending December 31, 2011, due to expected settlements. 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 2010, 2009, and 2008, the net interest expense related to unrecognized tax benefits was $9 million, $9 million, and $4 million, respectively, of which a respective $5 million, $5 million, and $1 million expense component was deferred as a regulatory asset by PEF, which is amortized as a charge to interest expense over a three-year period or less. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2010 and 2009, there were no penalties related to unrecognized tax benefits. During 2008, less than $1 million was recorded for penalties related to unrecognized tax benefits. At December 31, 2010, 2009, and 2008, we had accrued $45 million, $36 million, and $27 million, respectively, for interest and penalties, which are included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four coal-based solid synthetic fuels limited liability companies, 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 3A). 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, 2010 and 2009 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 2010 and 2009 was insignificant.

The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income (See Note 20). At December 31, 2010 and 2009, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million.

16. BENEFIT PLANS

A. Postretirement Benefits

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

COSTS OF BENEFIT PLANS

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

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

The table below provides 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.

	Pension Benefits			OPEB		
(in millions)	**2010**	2009	2008	**2010**	2009	2008
Service cost	**$48**	$42	$46	**$16**	$7	$8
Interest cost	**140**	138	128	**45**	31	34
Expected return on plan assets	**(157)**	(133)	(170)	**(4)**	(4)	(6)
Amortization of actuarial loss[a]	**51**	54	8	**13**	1	1
Other amortization, net[a]	**6**	6	2	**5**	5	5
Net periodic cost before deferral[b]	**$88**	$107	$14	**$75**	$40	$42

[a] Adjusted to reflect PEF's rate treatment (See Note 16B).
[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 7C.

The following table provides a summary of amounts recognized in other comprehensive income and other comprehensive income reclassification adjustments for amounts included in net income for 2010, 2009 and 2008. The tables also include comparable items that affected regulatory assets of PEC and PEF. For PEC and PEF, 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.

(in millions)	Pension Benefits **2010**	2009	2008	OPEB **2010**	2009	2008
Other comprehensive income (loss)						
Recognized for the year						
Net actuarial (loss) gain	**$(11)**	$(1)	$(64)	**$(10)**	$4	$(8)
Other, net	**–**	–	(6)	**–**	–	–
Reclassification adjustments						
Net actuarial loss	**4**	5	1	**–**	1	–
Other, net	**–**	–	1	**–**	1	–
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	**(65)**	10	(735)	**(164)**	64	(73)
Other, net	**–**	(3)	(36)	**–**	–	–
Amortized to income[a]						
Net actuarial loss	**47**	49	7	**13**	–	1
Other, net	**6**	6	1	**5**	4	5

[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 in the calculation of our net periodic cost:

	Pension Benefits **2010**	2009	2008	OPEB **2010**	2009	2008
Discount rate	**6.00%**	6.30%	6.20%	**6.05%**	6.20%	6.20%
Rate of increase in future compensation						
Bargaining	**4.50%**	4.25%	4.25%	**–**	–	–
Supplementary plans	**5.25%**	5.25%	5.25%	**–**	–	–
Expected long-term rate of return on plan assets	**8.75%**	8.75%	9.00%	**6.60%**	6.80%	8.10%

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 2009, primarily due to the uncertainties resulting from the severe capital market deterioration in 2008. 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 benefit obligations and the funded status as of December 31, 2010 and 2009 are presented in the table below, followed by related supplementary information.

(in millions)	Pension Benefits 2010	Pension Benefits 2009	OPEB 2010	OPEB 2009
Projected benefit obligation at January 1	**$2,422**	$2,234	**$543**	$608
Service cost	**48**	42	**16**	7
Interest cost	**140**	138	**45**	31
Settlements	**–**	(9)	**–**	–
Benefit payments	**(129)**	(124)	**(44)**	(40)
Plan amendment	**1**	3	**–**	–
Actuarial loss (gain)	**127**	138	**173**	(63)
Obligation at December 31	**2,609**	2,422	**733**	543
Fair value of plan assets at December 31	**1,891**	1,673	**33**	55
Funded status	**$(718)**	$(749)	**$(700)**	$(488)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.609 billion and $2.422 billion at December 31, 2010 and 2009, respectively. Those plans had accumulated benefit obligations totaling $2.563 billion and $2.378 billion at December 31, 2010 and 2009, respectively, and plan assets of $1.891 billion and $1.673 billion at December 31, 2010 and 2009, respectively.

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

(in millions)	Pension Benefits 2010	Pension Benefits 2009	OPEB 2010	OPEB 2009
Current liabilities	**$(10)**	$(9)	**$(22)**	$–
Noncurrent liabilities	**(708)**	(740)	**(678)**	(488)
Funded status	**$(718)**	$(749)	**$(700)**	$(488)

The following table provides a summary of amounts not yet recognized as a component of net periodic cost at December 31:

(in millions)	Pension Benefits 2010	Pension Benefits 2009	OPEB 2010	OPEB 2009
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	**$90**	$83	**$5**	$(5)
Other, net	**9**	10	**1**	–
Recognized in regulatory assets, net				
Net actuarial loss	**824**	806	**183**	32
Other, net	**55**	59	**9**	14
Total not yet recognized as a component of net periodic cost[a]	**$978**	$958	**$198**	$41

[a] All components are adjusted to reflect PEF's rate treatment (See Note 16B).

The following table presents the amounts we expect to recognize as components of net periodic cost in 2011:

(in millions)	Pension Benefits	OPEB
Amortization of actuarial loss[a]	$58	$12
Amortization of other, net[a]	7	5

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

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

	Pension Benefits 2010	Pension Benefits 2009	OPEB 2010	OPEB 2009
Discount rate	**5.65%**	6.00%	**5.75%**	6.05%
Rate of increase in future compensation				
Bargaining	**4.50%**	4.50%	**–**	–
Supplementary plans	**5.25%**	5.25%	**–**	–
Initial medical cost trend rate for pre-Medicare Act benefits	**–**	–	**8.50%**	8.50%
Initial medical cost trend rate for post-Medicare Act benefits	**–**	–	**8.50%**	8.50%
Ultimate medical cost trend rate	**–**	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	**–**	–	**2017**	2016

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.

(in millions)	
1 percent increase in medical cost trend rate	
Effect on total of service and interest cost	$3
Effect on postretirement benefit obligation	46
1 percent decrease in medical cost trend rate	
Effect on total of service and interest cost	(2)
Effect on postretirement benefit obligation	(31)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation table that follows, our employer contributions for 2010 and 2009 include contributions directly to pension plan assets of $129 million and $222 million, respectively. Substantially all of the remaining employer contributions represent benefit payments made directly from our assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the cost after participant contributions. Participant contributions represent approximately 15 percent of gross benefit payments. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2010 and 2009, the subsidies totaled $3 million.

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

	Pension Benefits		OPEB	
(in millions)	**2010**	2009	**2010**	2009
Fair value of plan assets January 1	**$1,673**	$1,285	**$55**	$52
Actual return on plan assets	**208**	279	**2**	9
Benefit payments, including settlements	**(129)**	(133)	**(44)**	(40)
Employer contributions	**139**	242	**20**	34
Fair value of plan assets at December 31	**$1,891**	$1,673	**$33**	$55

Our 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 rolling 10-year annual return of 6 percent over the rate of inflation. The current target pension asset allocations are 40 percent domestic equity, 20 percent international equity, 25 percent domestic fixed income, 10 percent private equity and timber and 5 percent 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. International equity includes investments in foreign stocks in both developed and emerging market countries, using a mix of value and growth based investment strategies. Domestic fixed income primarily includes domestic investment grade fixed income investments. A substantial portion of OPEB plan assets are managed with pension assets. The remaining OPEB plan assets, representing all PEF's OPEB plan assets, are invested in domestic governmental securities.

The following table sets forth by level within the fair value hierarchy of our pension plan assets at December 31, 2010 and 2009. See Note 13 for detailed information regarding the fair value hierarchy.

	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**
Interest rate swaps and other investments	**–**	**4**	**–**	**4**
Fair value of plan assets	**$470**	**$1,261**	**$160**	**$1,891**
2009				
Assets				
Cash and cash equivalents	$1	$96	$–	$97
Domestic equity securities	263	1	–	264
Private equity securities	–	–	122	122
Corporate bonds	–	67	–	67
U.S. state and municipal debt	–	4	–	4
U.S. and foreign government debt	25	95	–	120
Mortgage backed securities	–	22	–	22
Commingled funds	–	888	–	888
Hedge funds	–	47	2	49
Timber investments	–	–	14	14
Interest rate swaps and other investments	–	56	–	56
Total assets	$289	$1,276	$138	$1,703
Liabilities				
Foreign currency contracts	$5	$–	$–	$5
Interest rate swaps and other investments	–	25	–	25
Total liabilities	5	25	–	30
Fair value of plan assets	$284	$1,251	$138	$1,673

At December 31, 2010, our other postretirement benefit plan assets had a fair value of $33 million, which consisted of U.S. state and municipal assets classified as Level 2 in the fair value hierarchy as of December 31, 2010.

The following table sets forth the fair value hierarchy of our other postretirement plan assets at December 31, 2009. See Note 13 for detailed information regarding the fair value hierarchy.

	Other Postretirement Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash and cash equivalents	$–	$1	$–	$1
Domestic equity securities	4	–	–	4
Corporate bonds	–	1	–	1
U.S. state and municipal debt	–	32	–	32
U.S. and foreign government debt	–	2	–	2
Commingled funds	–	13	–	13
Hedge funds	–	1	–	1
Interest rate swaps and other investments	–	1	–	1
Fair value of plan assets	$4	$51	$–	$55

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**
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**
2009				
Balance at January 1	$111	$2	$18	$131
Net realized and unrealized (losses)[(a)]	(10)	–	(4)	(14)
Purchases, sales and distributions, net	21	–	–	21
Balance at December 31	$122	$2	$14	$138

[(a)] Substantially all amounts relate to investments held at December 31.

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 2011, we expect to make contributions of $300 million-$400 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 2011 through 2015 and in total for 2016 through 2020, in millions, are approximately $168, $176, $178, $189, $193 and $1,016, respectively. The expected benefit payments for the OPEB plan for 2011 through 2015 and in total for 2016 through 2020, in millions, are approximately $45, $48, $51, $53, $56 and $306, 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 2011 through 2015 and in total for 2016 through 2020, in millions, are approximately $4, $5, $5, $6, $6 and $43, 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 has been 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 16A is adjusted as appropriate to reflect PEF's rate treatment.

17. 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 13B 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 2011 and 2012. 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 Consolidated Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause.

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 $164 million and $146 million on the Consolidated Balance Sheets at December 31, 2010 and 2009, respectively. At December 31, 2010, Progress Energy had 259.9 million MMBtu notional of natural gas and 20.2 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, 2010, all open interest rate hedges will reach their mandatory termination dates within three years. At December 31, 2010, including amounts related to terminated hedges, we had $63 million of after-tax losses recorded in accumulated other comprehensive income related to forward starting swaps. It is expected that in the next twelve months losses of $7 million, net of tax, primarily related to terminated hedges, will be reclassified to interest expense. The actual amounts that will be reclassified to earnings may vary from the expected amounts as a result of 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, 2009, including amounts related to terminated hedges, we had $35 million of after-tax losses recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2008, including amounts related to terminated hedges, we had $56 million of after-tax losses recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2010, we had $1.050 billion notional of open forward starting swaps. During January 2011, Progress Energy terminated $300 million notional of forward starting swaps in conjunction with the issuance of debt (See Note 11A).

At December 31, 2009, we had $325 million notional of open forward starting swaps.

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, 2010 and 2009, we did not have 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 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 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 with credit risk-related contingent features that are in a net liability position at December 31, 2010, is $446 million, for which we have posted collateral of $164 million in the normal course of business. If the credit risk-related contingent features underlying these agreements were triggered at December 31, 2010, we would have been required to post an additional $282 million of collateral with its counterparties.

D. Derivative Instrument and Hedging Activity Information

The following table presents the fair value of derivative instruments at December 31:

Instrument / Balance sheet location	2010		2009	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Interest rate derivatives				
Prepayments and other current assets	**$1**		$5	
Other assets and deferred debits	**3**		14	
Derivative liabilities, current		**$32**		$–
Derivative liabilities, long-term		**7**		–
Total derivatives designated as hedging instruments	**4**	**39**	19	–
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	**11**		11	
Other assets and deferred debits	**4**		9	
Derivative liabilities, current		**226**		189
Derivative liabilities, long-term		**268**		236
CVOs[b]				
Other liabilities and deferred credits		**15**		15
Fair value of derivatives not designated as hedging instruments	**15**	**509**	20	440
Fair value loss transition adjustment[c]				
Derivative liabilities, current		**1**		1
Derivative liabilities, long-term		**3**		4
Total derivatives not designated as hedging instruments	**15**	**513**	20	445
Total derivatives	**$19**	**$552**	$39	$445

[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 (See Note 15).
[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)	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Commodity cash flow derivatives	**$–**	$1	$(2)	**$–**	$–	$–	**$–**	$–	$–
Interest rate derivatives[c][d]	**(34)**	15	(35)	**(6)**	(6)	(3)	**3**	(3)	1
Total	**$(34)**	$16	$(37)	**$(6)**	$(6)	$(3)	**$3**	$(3)	$1

[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 in 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)	**2010**	2009	2008	**2010**	2009	2008
Commodity derivatives[a]	**$(324)**	$(659)	$174	**$(398)**	$(387)	$(653)

[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)	**2010**	2009	2008
Commodity derivatives[a]	**$–**	$1	$(3)
Fair value loss transition adjustment[a]	**1**	2	$3
CVOs[a]	**–**	19	–
Total	**$1**	$22	$–

[a] Amounts recorded in the Consolidated Statements of Income are classified in other, net.

18. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees 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, 2010, the Parent had issued $473 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.

19. 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, 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 (loss)	**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 (loss)	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
At and for the year ended December 31, 2008					
Revenues					
Unaffiliated	$4,429	$4,730	$8	$–	$9,167
Intersegment	–	1	361	(362)	–
Total revenues	4,429	4,731	369	(362)	9,167
Depreciation, amortization and accretion	518	306	15	–	839
Interest income	12	9	38	(35)	24
Total interest charges, net	207	208	259	(35)	639
Income tax expense (benefit)[a]	298	181	(87)	–	392
Ongoing Earnings (loss)	531	383	(138)	–	776
Total assets	13,165	12,471	17,483	(13,246)	29,873
Capital and investment expenditures	939	1,601	33	(13)	2,560

[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 is computed as GAAP net income attributable to controlling interests after excluding 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 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 has determined that impairments, charges (and subsequent adjustments, if any) recognized for the retirement of generating units prior to the end of their estimated useful lives, cumulative prior period adjustments, net valuation allowances and operating results of discontinued operations are not representative of our ongoing operations and should be excluded 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)	**2010**	2009	2008
Ongoing Earnings	**$889**	$846	$776
CVO mark-to-market (Note 15)	**–**	19	–
Impairment, net of tax benefit of $4 and $1	**(6)**	(2)	–
Plant retirement adjustment, net of tax benefit of $1 and $11	**(1)**	(17)	–
Change in tax treatment of the Medicare Part D subsidy (Note 16)	**(22)**	–	–
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax benefit of $7	**–**	(10)	–
Valuation allowance and related net operating loss carry forward	**–**	–	(3)
Continuing income attributable to noncontrolling interests, net of tax	**7**	4	5
Income from continuing operations	**867**	840	778
Discontinued operations, net of tax	**(4)**	(79)	58
Net income attributable to noncontrolling interests, net of tax	**(7)**	(4)	(6)
Net income attributable to controlling interests	**$856**	$757	$830

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income; AFUDC equity, which represents the estimated equity costs of capital funds necessary to finance the construction of new regulated assets; and other, net. The components of other, net as shown on the accompanying Consolidated Statements of Income are presented below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities.

(in millions)	**2010**	2009	2008
Nonregulated energy and delivery services income, net	**$10**	$17	$17
CVOs unrealized gain, net (Note 15)	**–**	19	–
Investment gains (losses), net	**9**	(9)	(13)
Donations	**(23)**	(20)	(25)
Other, net	**4**	(1)	4
Other, net	**$–**	$6	$(17)

21. ENVIRONMENTAL MATTERS

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

A. Hazardous and Solid Waste

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the United States Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida, or potentially responsible party (PRP) groups as described below in greater detail. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Note 7). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted. A discussion of sites by legal entity follows.

The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion residues, 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. On June 21, 2010, the EPA proposed two options for new rules to regulate coal combustion residues. The first option would create a comprehensive program of federally enforceable requirements for coal combustion residues management and disposal as hazardous waste. The other option would have the EPA set performance standards for coal combustion residues management facilities and regulate disposal of coal combustion residues as nonhazardous waste. 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 residues that are recycled. A final rule is expected in late 2011 or 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.

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 on the Consolidated 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 were included in other current liabilities and other liabilities and deferred credits on the Consolidated Balance Sheets:

(in millions)	MGP and Other Sites	Remediation of Distribution and Substation Transformers	Total
Balance, December 31, 2009	**$22**	**$20**	**$42**
Amount accrued for environmental loss contingencies[a]	**8**	**13**	**21**
Expenditures for environmental loss contingencies[a]	**(10)**	**(18)**	**(28)**
Balance, December 31, 2010[b]	**$20**	**$15**	**$35**
Balance, December 31, 2008	$31	$22	$53
Amount accrued for environmental loss contingencies[a]	3	13	16
Expenditures for environmental loss contingencies[a]	(12)	(15)	(27)
Balance, December 31, 2009[b]	$22	$20	$42

[a] Amounts accrued and expenditures are for the years ended December 31. For the year ended December 31, 2008, we accrued $8 million for the remediation of MGP and other sites and $17 million for the remediation of distribution and substation transformers. For the year ended December 31, 2008, we spent $8 million for the remediation of MGP and other sites and $28 million for the remediation of distribution and substation transformers.

[b] Expected to be paid out over one to 15 years.

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, 2010 and December 31, 2009, PEC's recorded liability for the site was approximately $5 million and $4 million, respectively. 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 also set a trial date for May 7, 2012. On June 15, 2010, the court entered a case management order and discovery is proceeding. 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 the operable unit for further investigation at the Ward facility and certain adjacent areas (Ward OU2). The EPA's estimate for the selected remedy for Ward OU1 is approximately $6 million. The EPA offered PEC and the other PRPs the opportunity to negotiate implementation of a response action for Ward OU1 and a remedial investigation and feasibility study for Ward OU2, as well as reimbursement to the EPA of approximately $1 million for the EPA's past expenditures in addressing conditions at the site. In 2009, PEC and several of the other participating PRPs at the Ward site submitted a letter containing a good faith response to the EPA's special notice letter. Another group of PRPs separately submitted a good faith response, which the EPA advised would be used to negotiate implementation of the required actions. The other PRPs' good faith response was subsequently withdrawn. Discussions among representatives of certain PRPs, including PEC, and the EPA are ongoing. Although a loss is considered probable, an agreement among the PRPs for these matters has not been reached; consequently, it is not possible at this time to reasonably estimate the total amount of PEC's obligation, 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. At December 31, 2010 and December 31, 2009, PEF has recorded a regulatory asset for the probable recovery of costs through the ECRC related to the sites included under the agreement with the FDEP.

B. Air and Water Quality

At December 31, 2010 and 2009, we were subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations included the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the North Carolina Clean Smokestacks Act, enacted in June 2002

(Clean Smokestacks Act) and mercury regulation. PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions have been placed in service. PEF's CAIR projects have been placed in service.

In 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) initially vacated the CAIR in its entirety and subsequently remanded the rule without vacating it for the EPA to conduct further proceedings consistent with the court's prior opinion. On August 2, 2010, the EPA published the proposed Transport Rule, which is the regulatory program that will replace the CAIR when finalized. The proposed Transport Rule contains new emissions trading programs for nitrogen oxides (NOx) and sulfur dioxide (SO_2) emissions as well as more stringent overall emissions targets. The EPA plans to finalize the Transport Rule in the spring of 2011. Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe both PEC and PEF are well positioned to comply with the Transport Rule. The outcome of the EPA's rulemaking cannot be predicted. Because of the D.C. Court of Appeals' decision that remanded the CAIR, the current implementation of the CAIR continues to fulfill best available retrofit technology (BART) for NOx and SO_2 for BART-affected units under the CAVR. Should this determination change as the Transport Rule is promulgated, CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions for BART-eligible units.

In 2008, the D.C. Court of Appeals vacated the Clean Air Mercury Rule (CAMR). As a result, the EPA subsequently announced that it will develop a maximum achievable control technology (MACT) standard. The United States District Court for the District of Columbia has issued an order requiring the EPA to issue a final MACT standard for power plants by November 16, 2011. In addition, North Carolina adopted a state-specific requirement. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. We are currently evaluating the impact of these decisions. The outcome of this matter cannot be predicted.

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). The CR4 project was placed in service in May 2010 and the CR5 project was placed in service in December 2009. 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 7C, PEF identified in its 2010 nuclear cost-recovery filing regulatory and economic conditions causing schedule shifts such that major construction activities 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.

The EPA is continuing to record allowance allocations under the CAIR NOx trading program, in some cases for years beyond the estimated 2011 finalization of the Transport Rule. The EPA's continued recording of CAIR NOx allowance allocations does not guarantee that allowances will continue to be usable for compliance after a replacement rule is finalized or that they will continue to have value in the future. SO_2 emission allowances will be utilized to comply with existing Clean Air Act requirements. PEF's CAIR expenses, including NOx allowance inventory expense, are recoverable through the ECRC. At December 31, 2010 and 2009, PEC had approximately $8 million and $13 million, respectively, in SO_2 emission allowances and an immaterial amount of NOx emission allowances. At December 31, 2010 and 2009, PEF had approximately $5 million and $7 million, respectively, in SO_2 emission allowances and approximately $28 million and $36 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, 2010, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

(in millions)	2011	2012	2013	2014	2015	Thereafter	Total
Fuel[a]	$2,407	$2,365	$1,985	$1,441	$1,224	$6,719	$16,141
Purchased power	475	457	440	382	389	3,461	5,604
Construction obligations[a]	507	230	122	51	55	14	979
Other purchase obligations	122	72	66	41	69	697	1,067
Total	$3,511	$3,124	$2,613	$1,915	$1,737	$10,891	$23,791

[a] PEF signed an engineering, procurement and construction (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 $2.890 billion, $2.921 billion and $3.078 billion for 2010, 2009 and 2008, 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 for the planned Levy nuclear units. The construction schedule and startup dates were subsequently revised. (See discussion following under "Construction Obligations.") This approximately $400 million contract (for fuel plus related core components), which is excluded from the previous table, is for the period from 2019 through 2033, and contains exit provisions with termination fees that vary based on the circumstance.

Both PEC and PEF have ongoing purchased power contracts, including renewable energy contracts, with certain co-generators, primarily qualified facilities (QFs), with expiration dates ranging from 2011 to 2030. These purchased power contracts generally provide for capacity and energy payments or bundled capacity and energy payments.

PEC executed two long-term tolling agreements for the purchase of all of the power generated from Broad River LLC's Broad River facility. One agreement provides for the purchase of approximately 500 MW of capacity through May 2021 with average minimum annual payments of approximately $24 million, primarily representing capital-related capacity costs. The second agreement provides for the additional purchase of approximately 335 MW of capacity through February 2022 with average annual payments of approximately $24 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River LLC's Broad River facility agreements amounted to $115 million, $46 million and $44 million in 2010, 2009 and 2008, respectively.

In 2007, PEC executed long-term agreements for the purchase of power from Southern Power Company. The agreements provide for firm unit capacity and energy purchases of 305 MW (68 percent of net output) for 2010, 310 MW (30 percent of net output) for 2011 and 150 MW (33 percent of net output) annually thereafter through 2019. Estimated payments for capacity under the agreements are approximately $25 million for 2011 and $12 million annually thereafter through 2019. Total purchases for both capacity and energy under the agreements were $92 million in 2010.

PEC has various pay-for-performance contracts with QFs, including renewable energy, for approximately 31 MW of firm capacity expiring at various times through 2030. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $8 million, $24 million and $55 million in 2010, 2009 and 2008, respectively.

PEF has firm contracts for approximately 657 MW of purchased power with other utilities, including a contract with Southern Company for approximately 424 MW (25 percent of net output) of purchased power annually, which started in 2010 and extends into 2016. A contract with Southern Company for approximately 414 MW (12 percent of net output) of purchased power ended in 2010. Total purchases, for both energy and capacity, under agreements with other utilities amounted to $189 million, $149 million and $178 million for 2010, 2009 and 2008, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $64 million, $53 million, $46 million, $65 million and $65 million for 2011 through 2015, respectively, and $24 million payable thereafter.

PEF has ongoing purchased power contracts with certain QFs for 682 MW of firm capacity with expiration dates ranging from 2011 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. All ongoing commitments have been approved by the FPSC. Total capacity and energy payments made under these contracts amounted to $469 million, $435 million and $440 million for 2010, 2009 and 2008, respectively. Minimum expected future capacity payments under these contracts are $300 million, $313 million, $309 million, $238 million and $244 million for 2011 through 2015, respectively, and $3.006 billion payable thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

In 2009, PEC executed a long-term coal transportation agreement by combining, amending and restating previous agreements with Norfolk Southern Railroad. This agreement will support PEC's coal supply needs through June 2020. Expected future transportation payments under this agreement are $223 million, $235 million, $224 million, $213 million and $218 million for 2011 through 2015, respectively, with approximately $1.322 billion payable thereafter. Coal transportation expenses under these agreements were approximately $231 million and $283 million for 2010 and 2009, respectively. PEC's state utility commissions allow fuel-related costs to be recovered through fuel cost-recovery clauses.

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 May 2011 through May 2033. The estimated total cost to PEC associated with these agreements is approximately $2.042 billion, approximately $426 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 the Consolidated Balance Sheets until approximately 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 fuel commitments or in capital lease assets or obligations.

In April 2008, (and as amended in February 2009), PEF entered into a conditional contract with a pipeline entity for firm pipeline transportation capacity to support PEF's gas supply needs for the period from April 2011 through March 2036. The total cost to PEF associated with this agreement is estimated to be approximately $890 million. In addition to this contract, PEF has entered into additional gas transportation arrangements for the period from 2011 through 2036. The total current notional cost of these additional agreements is estimated to be approximately $281 million. All of these contracts are subject to conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in fuel commitments.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $703 million, $818 million and $1.018 billion for 2010, 2009 and 2008, 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 $555 million, $199 million and $140 million for 2010, 2009 and 2008, respectively. Payments for 2010 primarily relate to construction of generating facilities at our sites in Richmond County, N.C., Wayne County, N.C., and New Hanover County, N.C., as discussed in Note 7B.

PEF made payments of $63 million, $243 million and $117 million for 2010, 2009 and 2008, respectively, toward long lead equipment and engineering related to the Levy EPC. Additionally, PEF has other construction obligations related to various capital projects including new generation, transmission and environmental compliance. Total payments under PEF's other construction-related contracts were $84 million, $376 million and $761 million for 2010, 2009 and 2008, respectively.

The future construction obligations presented in the previous table for Progress Energy excludes the 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 7C in PEF's 2010 nuclear cost-recovery filing, 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, excavation and foundation preparation work anticipated in the initial schedule cannot begin until the COL is issued, resulting in a project shift of at least 20 months. Since then, regulatory and economic conditions identified in the 2010 nuclear cost-recovery filing have changed such that major construction activities on the Levy project are being postponed until after the NRC issues the COL, 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. Prior to the 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 the timing of when those obligations will be satisfied or the magnitude of any change. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF may incur fees and charges related to the disposition of outstanding purchase orders on long lead time equipment for the Levy nuclear project, which could be material. In June 2010, PEF completed its long lead time equipment disposition analysis to minimize the impact associated with the schedule shift. As a result of the analysis, PEF will continue with selected components of the long lead time equipment. Work has been 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. PEF has been in suspension negotiations with the selected equipment vendors, which we anticipate concluding by the end of the first quarter of 2011. In its April 30, 2010 nuclear cost-recovery filing, PEF included for rate-making purposes a point estimate of potential Levy disposition fees and charges of $50 million, subject to true-up. However, the amount of disposition fees and charges, if any, cannot be determined until suspension negotiations are completed. 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 Richmond County, N.C., 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 $124 million, $56 million and $110 million for 2010, 2009 and 2008, respectively.

PEC has various other purchase obligations, including obligations for parts and equipment, limestone supply and fleet vehicles. Total purchases under these contracts were $55 million, $14 million and $18 million for 2010, 2009 and 2008, respectively.

On October 1, 2010, PEC entered into long-term service agreements for its Richmond County, N.C., Wayne County, N.C., and New Hanover County, N.C., generating facilities, covering projected maintenance events for each facility through 2033, 2028 and 2029, respectively. The total cost to PEC associated with these agreements is estimated to be approximately $379 million over the term of the agreements. Expected future payments under these agreements are $6 million, $7 million, $11 million, $16 million and $36 million for 2011 through 2015, respectively, with approximately $303 million payable thereafter. Total purchases under these agreements were not material for 2010.

Among PEF's other purchase obligations, PEF has long-term service agreements for the Hines Energy Complex and the Bartow Plant, emission obligations and fleet vehicles. Total payments under these contracts were $35 million, $22 million and $58 million for 2010, 2009 and 2008, respectively. Future obligations are primarily comprised of the long-term service agreements.

B. Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Our rent expense under operating leases totaled $39 million, $37 million and $38 million for 2010, 2009 and 2008, respectively. Our purchased power expense under agreements classified as operating leases was approximately $61 million, $11 million and $152 million in 2010, 2009 and 2008, respectively.

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

(in millions)	**2010**	2009
Buildings	**$267**	$267
Less: Accumulated amortization	**(46)**	(37)
Total	**$221**	$230

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 capital lease expense is generally included in O&M or purchased power expense. Our capital lease expense totaled $25 million, $26 million and $26 million for 2010, 2009 and 2008, respectively.

At December 31, 2010, minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable operating and capital leases were:

(in millions)	Capital	Operating
2011	$28	$37
2012	28	55
2013	36	80
2014	26	78
2015	25	77
Thereafter	227	866
Minimum annual payments	370	1,193
Less amount representing imputed interest	(149)	
Total	$221	$1,193

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

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

In 2009, PEC entered into a 240-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $10 million from July 2012 through September 2017, for a total of approximately $52 million.

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

In 2005, PEF entered into an agreement for a capital lease for a building completed during 2006. The lease term expires March 2047 and provides for minimum annual payments 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 lease, approximately $51 million of rental expense will be recorded in the Consolidated Statements of Income.

In 2006, PEF extended the terms of a 517-MW (100 percent of net output) tolling agreement for purchased power, which is classified as a capital lease of the related plant, for an additional 10 years. The agreement calls for minimum annual payments of approximately $21 million from April 2007 through April 2024, for a total of approximately $348 million.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases were $11 million for 2011 and none thereafter. PEC's rents received are contingent upon usage and totaled $33 million, $34 million, $33 million for 2010, 2009 and 2008, respectively. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $85 million, $84 million and $81 million for 2010, 2009 and 2008, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2011 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, 2010, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Consolidated Balance Sheets.

At December 31, 2010, 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, 2010, our estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $307 million. Related to the sales of businesses, the latest specified notice period extends until 2013 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. At December 31, 2010 and 2009, we had recorded liabilities related to guarantees and indemnifications to third parties of approximately $31 million and $34 million, respectively. During the year ended December 31, 2010, our accruals and expenditures related to guarantees and indemnifications were not material. 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

ENVIRONMENTAL

We are subject to federal, state and local regulations regarding environmental matters (See Note 21).

SPENT NUCLEAR FUEL MATTERS

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

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

In 2008, the Utilities received a ruling from the United States Court of Federal Claims awarding $83 million in the claim against the DOE for failure to abide by a contract for federal disposition of spent nuclear fuel. A request for reconsideration filed by the United States Department of Justice resulted in an immaterial reduction of the award. Substantially all of the award relates to costs incurred by PEC. On August 15, 2008, the Department of Justice appealed the United States Court of Federal Claims ruling to the D.C. Court of Appeals. On July 21, 2009, the D.C. Court of Appeals vacated and remanded the calculation of damages back to the Trial Court but affirmed the portion of damages awarded that were directed to overhead costs and other indirect expenses. The Department of Justice requested a rehearing en banc but the D.C. Court of Appeals denied the motion on November 3, 2009. In the event that the Utilities recover damages in this matter, such recovery will primarily offset capital assets and therefore is not expected to have a material impact on the Utilities' results of operations. However, the Utilities 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. 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. On December 17, 2010, we filed our initial appellate brief. 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.

NOTICE OF VIOLATION

On April 29, 2009, the EPA issued a notice of violation and opportunity to show cause with respect to a 16,000-gallon oil spill at one of PEC's substations in 2007. The notice of violation did not include specified sanctions sought. Subsequently, the EPA notified PEC that the agency was seeking monetary sanctions that are *de minimus* to our results of operations or financial condition. PEC has entered into consent agreements with the EPA resolving all issues and requiring *de minimus* payment of penalties and performance.

FLORIDA NUCLEAR COST RECOVERY

On February 8, 2010, a lawsuit was filed against PEF in state circuit court in Sumter County, Fla., alleging that the Florida nuclear cost-recovery statute (Section 366.93, Florida Statutes) violates the Florida Constitution, and seeking a refund of all monies collected by PEF pursuant to that statute with interest. The complaint also requests that the court grant class action status to the plaintiffs. On April 6, 2010, PEF filed a motion to dismiss the complaint. The trial judge issued an order on May 3, 2010, dismissing the complaint. The plaintiffs filed an amended complaint on June 1, 2010. PEF believes the lawsuit is without merit and filed a motion to dismiss the amended complaint on July 12, 2010. On October 1, 2010, the plaintiffs filed an appeal of the trial court's order dismissing the complaint. Initial and reply briefs have been filed by the appellants and PEF. The appellants filed their response brief on January 25, 2011. We cannot predict the outcome of this matter.

OTHER LITIGATION MATTERS

We 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, 2010, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional, and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances, and as disclosed in Note 11B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a 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. 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, 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 STATEMENT OF INCOME

Year ended December 31, 2008 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$4,738	$4,429	$–	$9,167
Affiliate revenues	–	–	361	(361)	–
Total operating revenues	–	4,738	4,790	(361)	9,167
Operating expenses					
Fuel used in electric generation	–	1,675	1,346	–	3,021
Purchased power	–	953	346	–	1,299
Operation and maintenance	3	813	1,346	(342)	1,820
Depreciation, amortization and accretion	–	306	533	–	839
Taxes other than on income	–	309	207	(8)	508
Other	–	1	(4)	–	(3)
Total operating expenses	3	4,057	3,774	(350)	7,484
Operating (loss) income	(3)	681	1,016	(11)	1,683
Other income (expense)					
Interest income	11	9	16	(12)	24
Allowance for equity funds used during construction	–	95	27	–	122
Other, net	–	(18)	(4)	5	(17)
Total other income, net	11	86	39	(7)	129
Interest charges					
Interest charges	201	263	227	(12)	679
Allowance for borrowed funds used during construction	–	(28)	(12)	–	(40)
Total interest charges, net	201	235	215	(12)	639
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(193)	532	840	(6)	1,173
Income tax (benefit) expense	(85)	172	306	2	395
Equity in earnings of consolidated subsidiaries	941	–	–	(941)	–
Income from continuing operations	833	360	534	(949)	778
Discontinued operations, net of tax	(3)	61	–	–	58
Net income	830	421	534	(949)	836
Net income attributable to noncontrolling interests, net of tax	–	(6)	–	–	(6)
Net income attributable to controlling interests	$830	$415	$534	$(949)	$830

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
Income taxes receivable	14	1	90	(53)	52
Prepayments and other current assets	16	750	894	(220)	1,440
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 BALANCE SHEET

December 31, 2009 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$–	$9,733	$9,886	$114	$19,733
Current assets					
Cash and cash equivalents	606	72	47	–	725
Receivables, net	–	358	442	–	800
Notes receivable from affiliated companies	30	46	303	(379)	–
Regulatory assets	–	54	88	–	142
Derivative collateral posted	–	139	7	–	146
Income taxes receivable	5	97	50	(7)	145
Prepayments and other current assets	14	800	935	(176)	1,573
Total current assets	655	1,566	1,872	(562)	3,531
Deferred debits and other assets					
Investment in consolidated subsidiaries	13,348	–	–	(13,348)	–
Regulatory assets	–	1,307	873	(1)	2,179
Goodwill	–	–	–	3,655	3,655
Nuclear decommissioning trust funds	–	496	871	–	1,367
Other assets and deferred debits	166	202	923	(520)	771
Total deferred debits and other assets	13,514	2,005	2,667	(10,214)	7,972
Total assets	$14,169	$13,304	$14,425	$(10,662)	$31,236
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$9,449	$4,590	$5,085	$(9,675)	$9,449
Noncontrolling interests	–	3	3	–	6
Total equity	9,449	4,593	5,088	(9,675)	9,455
Preferred stock of subsidiaries	–	34	59	–	93
Long-term debt, affiliate	–	309	115	(152)	272
Long-term debt, net	4,193	3,883	3,703	–	11,779
Total capitalization	13,642	8,819	8,965	(9,827)	21,599
Current liabilities					
Current portion of long-term debt	100	300	6	–	406
Short-term debt	140	–	–	–	140
Notes payable to affiliated companies	–	376	3	(379)	–
Derivative liabilities	–	161	29	–	190
Other current liabilities	261	941	902	(182)	1,922
Total current liabilities	501	1,778	940	(561)	2,658
Deferred credits and other liabilities					
Noncurrent income tax liabilities	–	320	1,258	(382)	1,196
Regulatory liabilities	–	1,103	1,293	114	2,510
Other liabilities and deferred credits	26	1,284	1,969	(6)	3,273
Total deferred credits and other liabilities	26	2,707	4,520	(274)	6,979
Total capitalization and liabilities	$14,169	$13,304	$14,425	$(10,662)	$31,236

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)
Cash distributions to noncontrolling interest	–	(3)	–	(3)	(6)
Changes in advances from affiliated companies	–	(201)	–	201	–
Contributions from parent	–	33	152	(185)	–
Other financing activities	–	(11)	(130)	128	(13)
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 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)
Cash distributions to noncontrolling interests	–	(3)	–	(3)	(6)
Changes in advances from affiliated companies	–	170	–	(170)	–
Contributions from parent	–	653	49	(702)	–
Other financing activities	(2)	(9)	12	13	14
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

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2008 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash (used) provided by operating activities	$(90)	$221	$1,114	$(27)	$1,218
Investing activities					
Gross property additions	–	(1,553)	(794)	14	(2,333)
Nuclear fuel additions	–	(43)	(179)	–	(222)
Proceeds from sales of assets to affiliated companies	–	12	–	(12)	–
Purchases of available-for-sale securities and other investments	(7)	(783)	(800)	–	(1,590)
Proceeds from available-for-sale securities and other investments	–	788	746	–	1,534
Changes in advances to affiliated companies	123	105	8	(236)	–
Return of investment in consolidated subsidiaries	20	10	–	(30)	–
Contributions to consolidated subsidiaries	(101)	–	–	101	–
Other investing activities	–	57	13	–	70
Net cash provided (used) by investing activities	35	(1,407)	(1,006)	(163)	(2,541)
Financing activities					
Issuance of common stock, net	132	–	–	–	132
Dividends paid on common stock	(642)	–	–	–	(642)
Dividends paid to parent	–	(33)	–	33	–
Dividends paid to parent in excess of retained earnings	–	–	(20)	20	–
Payments of short-term debt with original maturities greater than 90 days	(176)	–	–	–	(176)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	629	–	–	–	629
Net increase in short-term debt	15	371	110	–	496
Proceeds from issuance of long-term debt, net	–	1,475	322	–	1,797
Retirement of long-term debt	–	(577)	(300)	–	(877)
Cash distributions to noncontrolling interests	–	(85)	(10)	10	(85)
Changes in advances from affiliated companies	–	(21)	(215)	236	–
Contributions from parent	–	85	29	(114)	–
Other financing activities	–	1	(32)	5	(26)
Net cash (used) provided by financing activities	(42)	1,216	(116)	190	1,248
Net (decrease) increase in cash and cash equivalents	(97)	30	(8)	–	(75)
Cash and cash equivalents at beginning of year	185	43	27	–	255
Cash and cash equivalents at end of year	$88	$73	$19	$–	$180

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data was as follows:

(in millions except per share data)	First	Second	Third	Fourth
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**
2009				
Operating revenues	$2,442	$2,312	$2,824	$2,307
Operating income	393	379	676	324
Income from continuing operations	183	175	350	132
Net income	183	174	248	156
Net income attributable to controlling interests	182	174	247	154
Common stock data				
Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	0.66	0.62	1.24	0.46
Net income attributable to controlling interests	0.66	0.62	0.88	0.55
Dividends declared per common share	0.620	0.620	0.620	0.620
Market price per share				
High	40.85	38.20	40.05	42.20
Low	31.35	33.50	35.97	36.67

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 2009, we recognized $102 million of expense from discontinued operations attributable to controlling interests, net of tax, primarily related 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. In the fourth quarter of 2009, we recognized $25 million of earnings from discontinued operations primarily related to the tax benefits associated with the payment of the judgment. See Note 22D for additional information.

During the fourth quarter of 2009, we recorded a cumulative prior period adjustment related to certain employee life insurance benefits. The impact of this adjustment decreased total other income, net, by $17 million and decreased net income attributable to controlling interests by $10 million. The prior period adjustment is not material to 2009 or previously issued financial statements.

25. SUBSEQUENT EVENT – 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 continue as a wholly owned subsidiary of Duke Energy.

Under the terms of the Merger Agreement, each share of Progress Energy common stock will be cancelled 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 Merger Agreement contemplates a reverse stock split of Duke Energy stock, effective immediately prior to the Merger. The board of directors of Duke Energy has approved a reverse stock split, at a ratio of 1-for-2 or 1-for-3, to be determined by the board of directors of Duke Energy after consultation with Progress Energy, which is subject to approval by the shareholders of Duke Energy and would be effective prior to the Merger. Accordingly, the 2.6125 exchange ratio for Progress Energy common shares, options and equity awards will be adjusted based on Duke Energy's reverse stock split.

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 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, the SCPSC, the FPSC, the Indiana Utility Regulatory Commission, and the Ohio Public Utilities Commission.

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.

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 14).

The Merger Agreement contains certain termination rights for both companies and 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.

Progress Energy shareholders have 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. The lawsuits seek to prohibit the Merger and, in some cases, seek damages in the event that the Merger is completed. Progress Energy intends to vigorously defend against these claims. We cannot predict the outcome of this matter.

Years ended December 31 *(in millions, except per share data)*	**2010**	2009	2008	2007	2006
Operating results					
Operating revenues	**$10,190**	$9,885	$9,167	$9,153	$8,724
Income from continuing operations	**867**	840	778	702	567
Net income	**863**	761	836	496	620
Net income attributable to controlling interests	**856**	757	830	504	571
Per share data – basic and diluted earnings					
Income from continuing operations attributable to controlling interests, net of tax	**$2.96**	$2.99	$2.95	$2.70	$2.19
Net income attributable to controlling interests	**2.95**	2.71	3.17	1.96	2.27
Assets	**$33,054**	$31,236	$29,873	$26,338	$25,832
Capitalization and debt					
Common stock equity	**$10,023**	$9,449	$8,687	$8,395	$8,259
Noncontrolling interests	**4**	6	6	84	10
Preferred stock of subsidiaries	**93**	93	93	93	93
Long-term debt, net[a]	**12,137**	12,051	10,659	8,737	8,835
Current portion of long-term debt	**505**	406	–	877	324
Short-term debt	**–**	140	1,050	201	–
Capital lease obligations	**221**	231	239	247	72
Total capitalization and debt	**$22,983**	$22,376	$20,734	$18,634	$17,593
Other financial data					
Return on average common stock equity (percent)	**8.70**	8.13	9.59	5.97	7.05
Ratio of earnings to fixed charges	**2.72**	2.65	2.66	2.62	2.35
Number of common shareholders of record	**51,975**	53,922	55,919	58,991	64,899
Book value per common share	**$34.05**	$33.53	$32.97	$32.41	$32.53
Dividends declared per common share	**$2.48**	$2.48	$2.47	$2.45	$2.43
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	**44,971**	40,420	46,771	51,163	48,770
Nuclear	**21,624**	29,412	30,565	30,336	30,602
Combustion turbines/combined cycle	**27,856**	21,254	15,557	13,319	11,857
Hydro	**608**	651	429	415	594
Purchased	**13,473**	11,996	14,956	14,994	14,664
Total energy supply (Company share)	**108,532**	103,733	108,278	110,227	106,487
Jointly owned share[b]	**5,228**	5,500	5,780	5,351	5,224
Total system energy supply	**113,760**	109,233	114,058	115,578	111,711

[a] Includes long-term debt to affiliated trust of $273 million at December 31, 2010, $272 million at December 31, 2009 and 2008, and $271 million at December 31, 2007 and 2006 (See Note 23).

[b] Amounts represent joint owners' share of the energy supplied from the six generating facilities that are jointly owned.

Progress Energy's management uses Ongoing Earnings per share to evaluate the operations of the company and to establish goals for management and employees. 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 we believe are not representative of our fundamental core earnings. Ongoing Earnings as presented here may not be comparable to similarly titled measures used by other companies.

Reconciling adjustments from Ongoing Earnings to GAAP earnings for the years ended December 31 were as follows:

	2010	2009	2008
Ongoing Earnings per share	**$3.06**	$3.03	$2.96
CVO mark-to-market	–	0.07	–
Impairment	**(0.02)**	(0.01)	–
Plant retirement charge	–	(0.06)	–
Change in the tax treatment of the Medicare Part D subsidy	**(0.08)**	–	–
Cumulative prior period adjustment	–	(0.04)	–
Valuation allowance and related net operating loss carry forward	–	–	(0.01)
Discontinued operations	**(0.01)**	(0.28)	0.22
Reported GAAP earnings per share	**$2.95**	$2.71	$3.17
Shares outstanding (millions)	**291**	279	262

CVO Mark-to-Market

In connection with the acquisition of Florida Progress Corporation, Progress Energy issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on net after-tax cash flows above certain levels of four synthetic fuels facilities purchased by subsidiaries of Florida Progress Corporation in October 1999. The CVO liability is valued at fair value, and unrealized gains and losses from changes in fair value are recognized in earnings. Progress Energy is unable to predict the changes in the fair value of the CVOs, and management does not consider this adjustment to be representative of the company's fundamental core earnings.

Impairment

The company has recorded impairments of certain miscellaneous investments and other assets. Management does not consider this adjustment to be representative of the company's fundamental core earnings.

Plant Retirement Charges

The company recognized charges for the impact of PEC's decision to retire certain coal-fired generating units, with resulting reduced emissions for compliance with the Clean Smokestacks Act's 2013 emission targets. Since the coal-fired generating units will be retired prior to their estimated useful lives, management does not consider this charge to be representative of the company's fundamental core earnings.

Change in the Tax Treatment of the Medicare Part D Subsidy

The federal 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. Under prior law, employers could claim a deduction for the entire cost of providing retiree prescription drug coverage even though a portion of the cost was offset by the retiree drug subsidy received. 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. Under GAAP, changes in tax law are accounted for in the period of enactment. Management does not consider this change in tax treatment to be representative of the company's fundamental core earnings.

Cumulative Prior Period Adjustment

The company recorded a cumulative prior period adjustment charge related to certain employee life insurance benefits. Management does not consider this adjustment to be representative of the company's fundamental core earnings. The prior period adjustment was not material to 2009 or previously issued financial statements.

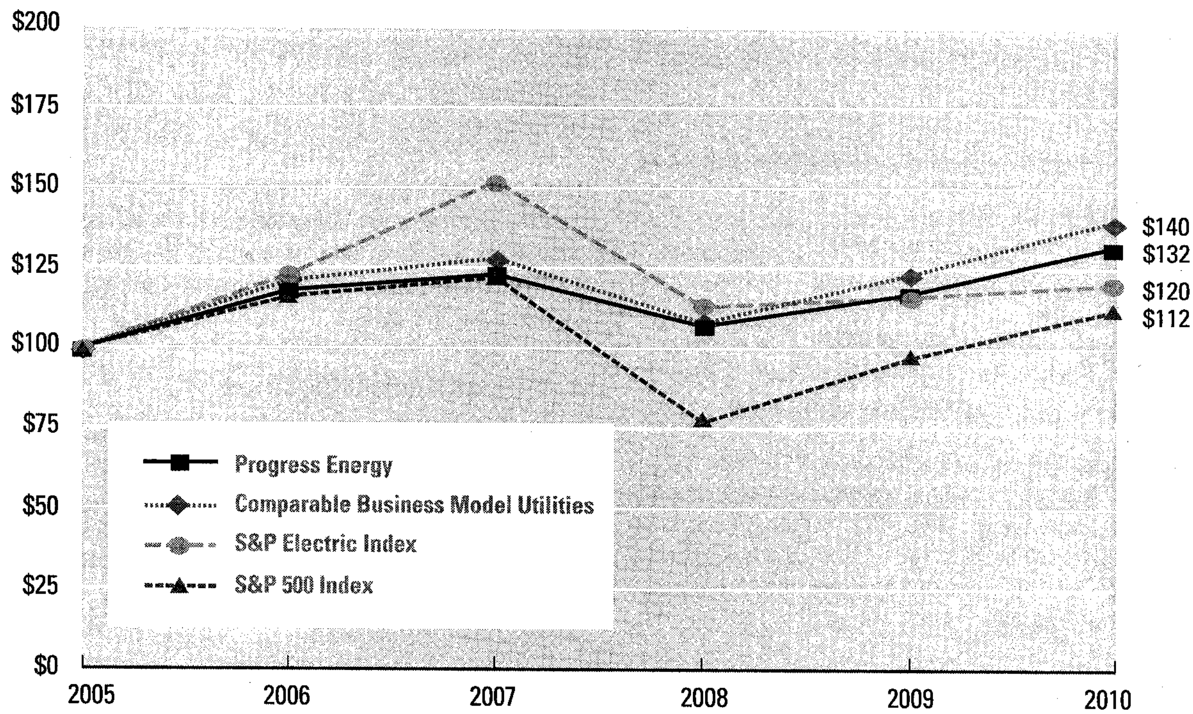
Valuation Allowance and Related Net Operating Loss Carry Forward

Progress Energy previously recorded a deferred tax asset for a state net operating loss carry forward upon the sale of nonregulated generating facilities and energy marketing and trading operations. In 2008, the company recorded an additional deferred tax asset related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings. The company also evaluated the total state net operating loss carry forward and partially impaired it by recording a valuation allowance, which more than offset the change in estimate. Management does not believe this net valuation allowance is representative of the company's fundamental core earnings.

Discontinued Operations

The company has reduced its business risk by exiting nonregulated businesses to focus on the core operations of the utilities. The discontinued operations of these nonregulated businesses decreased earnings per share by $0.01 for the quarter and increased earnings per share by $0.09 for the same period last year. The prior-year impact was due primarily to adjustments related to a litigation judgment against our former Synthetic Fuels businesses. Due to the disposition of these assets, management does not consider this activity to be representative of the company's fundamental core earnings.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN* AMONG PROGRESS ENERGY, INC., COMPARABLE BUSINESS MODEL UTILITIES, S&P ELECTRIC INDEX AND S&P 500 STOCK INDEX



Measurement Period (Fiscal Year Covered)	2005	2006	2007	2008	2009	2010
Progress Energy, Inc.	$100	$118	$123	$107	$117	$132
Comparable Business Model Utilities	100	121	128	108	123	140
S&P Electric Index	100	123	152	113	116	120
S&P 500 Index	100	116	122	77	97	112

*$100 invested on 12/31/2005 in Stock or Index. Including reinvestment of dividends. Fiscal year ended December 31.

Over the past decade, as deregulation has occurred in several geographic areas of the United States, the investor community has separated the utility industry into a number of subsectors. The two main themes of separation are 1) the aspect of the value chain in which the company participates: generation, transmission and/or delivery, and 2) the proportion of its business governed by rate-of-return regulation as opposed to competitive markets. Thus, the industry now 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 valuation characteristics and risk.

Progress Energy generally is identified as being in the regulated integrated subsector. This means Progress Energy and its peer companies are primarily rate-of-return regulated, operate in the full range of the value chain, and typically have requirements to serve all customers under state utility regulations. The companies similar to us from a business model perspective that are generally categorized in our subsector are American Electric Power, DPL, Duke Energy, Consolidated Edison, Great Plains Energy, Alliant Energy, NV Energy, PG&E, Pinnacle West, Portland General Electric, SCANA, Southern Company, Wisconsin Energy, Westar Energy and Xcel Energy.

It should be noted that, although the business models of several of these companies may not have been comparable to ours five years ago, their business models and ours are now similar due to industry evolution. The Company is providing this alternative market capitalization weighted index to show an additional comparison of Progress Energy's total return performance.

Notice of Annual Meeting

Progress Energy's 2011 annual meeting of shareholders will be held May 11, 2011, at 10 a.m. at the Progress Energy Center for the Performing Arts in Raleigh, N.C. A formal notice of the meeting will be mailed to shareholders in late March.

Transfer Agent and Registrar Mailing Address

Progress Energy, Inc.
c/o Computershare Trust Company
250 Royall Street
Canton, MA 02021
Toll-free phone number: **1.866.290.4388**

Shareholder Information and Inquiries

Obtain information on your account 24 hours a day, seven days a week by calling our stock transfer agent's shareholder information line. This automated system features Progress Energy's common stock closing price, dividend information and stock transfer information. Call toll-free **1.866.290.4388**.

Other questions concerning stock ownership may be directed to Progress Energy's Shareholder Relations by calling **919.546.3014** or by writing to the following address:

Progress Energy, Inc.
Shareholder Relations
410 S. Wilmington Street
Raleigh, NC 27601-1849

Stock Listings

Progress Energy's common stock is listed and traded under the symbol PGN on the New York Stock Exchange (NYSE) in addition to regional stock exchanges across the United States.

Shareholder Programs

Progress Energy offers the Progress Energy Investor Plus Plan, a direct stock-purchase and dividend-reinvestment plan, and direct deposit of cash dividends to bank accounts for the convenience of shareholders. For information on these programs, contact Computershare or the company.

Dividend-reinvestment statements and tax documents can be electronically delivered to shareholders. To take advantage of electronic delivery of documents, go to **computershare.com/investor**, log in to your account and select eDelivery options.

Securities Analyst Inquiries

Securities analysts, portfolio managers and representatives of financial institutions seeking information about Progress Energy should contact Robert F. Drennan, Jr., vice president, Investor Relations, at the corporate headquarters address or call **919.546.7474**.

Additional Information

Progress Energy files periodic reports with the Securities and Exchange Commission that contain additional information about the company. Copies are available to shareholders free of charge through the Investors section of our website at **www.progress-energy.com** or upon written request to the company's treasurer at the corporate headquarters address.

This annual report is submitted for shareholders' information and is available for delivery to shareholders in connection with our 2011 annual meeting of shareholders. It is not intended for use in connection with any sale or purchase of, or any offer or solicitation of offers to buy or sell, securities.

Cautionary Statement

This report contains forward-looking statements relating to Progress Energy's business. Our business is subject to numerous risks and uncertainties, which could cause actual results to differ materially from those expressed or implied by these forward-looking statements. We refer you to our Annual Report on Form 10-K for a discussion of such risks and uncertainties.

NOTICE OF ANNUAL MEETING AND PROXY STATEMENT

Progress Energy

Progress Energy, Inc.
410 S. Wilmington Street
Raleigh, NC 27601-1849

March 31, 2011

Dear Shareholder:

I am pleased to invite you to attend the 2011 Annual Meeting of the Shareholders of Progress Energy, Inc. The meeting will be held at 10:00 a.m. on May 11, 2011, at the Progress Energy Center for the Performing Arts, 2 East South Street, Raleigh, North Carolina.

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 Progress Energy, Inc. are the election of directors; an advisory (nonbinding) vote on executive compensation; an advisory (nonbinding) vote to determine whether to approve executive compensation every one, two or three years; and the ratification of the selection of the independent registered public accounting firm for Progress Energy, Inc.

We are pleased to take advantage of the Securities and Exchange Commission rules that permit companies to electronically deliver proxy materials to their shareholders. This process allows us to provide our shareholders with the information they need while lowering printing and mailing costs and more efficiently complying with our obligations under the securities laws. On or about March 31, 2011, we mailed to our registered and beneficial shareholders a Notice containing instructions on how to access our combined Proxy Statement and Annual Report and vote online.

Regardless of the size of your holdings, it is important that your shares be represented at the meeting. IN ADDITION TO VOTING IN PERSON AT THE MEETING, SHAREHOLDERS OF RECORD MAY VOTE VIA A TOLL-FREE TELEPHONE NUMBER OR OVER THE INTERNET. SHAREHOLDERS WHO RECEIVED A PAPER COPY OF THE PROXY STATEMENT AND THE ANNUAL REPORT MAY ALSO VOTE BY COMPLETING, SIGNING AND MAILING THE ACCOMPANYING PROXY CARD IN THE RETURN ENVELOPE PROVIDED AS SOON AS POSSIBLE. IF YOUR SHARES ARE HELD IN THE NAME OF A BANK, BROKER OR OTHER HOLDER OF RECORD, CHECK YOUR PROXY CARD TO SEE WHICH OPTIONS ARE AVAILABLE TO YOU. Voting by any of these methods will ensure that your vote is counted at the Annual Meeting if you do not attend in person.

I am delighted that you have chosen to invest in Progress Energy, Inc., and look forward to seeing you at the meeting. On behalf of the management and directors of Progress Energy, Inc., thank you for your continued support and confidence in 2011.

Sincerely,

William D. Johnson

William D. Johnson
Chairman of the Board, President and
Chief Executive Officer

VOTING YOUR PROXY IS IMPORTANT

Your vote is important. To ensure your representation at the Annual Meeting, please vote your shares as promptly as possible. In addition to voting in person, shareholders of record may **VOTE VIA A TOLL-FREE TELEPHONE NUMBER OR OVER THE INTERNET**, as instructed in the materials.

If you received this Proxy Statement by mail, 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.

PROGRESS ENERGY, INC.

410 S. Wilmington Street
Raleigh, North Carolina 27601-1849

NOTICE OF THE ANNUAL MEETING OF SHAREHOLDERS TO BE HELD ON

MAY 11, 2011

The Annual Meeting of the Shareholders of Progress Energy, Inc. (the "Company") will be held at 10:00 a.m. on May 11, 2011, at the Progress Energy Center for the Performing Arts, 2 East South Street, Raleigh, North Carolina. The meeting will be held in order to:

(1) Elect fourteen (14) 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) Vote on an advisory (nonbinding) proposal to determine whether the advisory (nonbinding) vote to approve executive compensation will occur every one, two or three years. The Board of Directors recommends a vote **FOR** the option of one year on this proposal.

(4) 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.

(5) Transact any other business as may properly be brought before the meeting.

All holders of the Company's Common Stock of record at the close of business on March 4, 2011, are entitled to attend the meeting and to vote. The stock transfer books will remain open.

By order of the Board of Directors

JOHN R. MCARTHUR
Executive Vice President, General Counsel
and Corporate Secretary

Raleigh, North Carolina
March 31, 2011

PROXY STATEMENT

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PROGRESS ENERGY, 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 10:00 a.m. on May 11, 2011, at the Progress Energy Center for the Performing Arts, 2 East South Street, Raleigh, North Carolina. (For directions to the meeting location, please see the map included at the end of this Proxy Statement.) Throughout this Proxy Statement, Progress Energy, Inc. is at times referred to as "Progress Energy," "we," "our" or "us." This Proxy Statement and form of proxy were first sent to shareholders on or about March 31, 2011.

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.

Copies of our Annual Report on Form 10-K, as amended, for the year ended December 31, 2010, including financial statements and schedules, are available upon written request, without charge, to the persons whose proxies are solicited. Any exhibit to the Form 10-K, as amended, 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, Progress Energy, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551. Our Form 10-K, as amended, 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.

In accordance with the "notice and access" rule adopted by the SEC, we are making our proxy materials available to our shareholders on the Internet, and we are mailing to our registered and beneficial holders a "Notice of Internet Availability of Proxy Materials" containing instructions on how to access our proxy materials and how to vote on the Internet and by telephone. If you received a "Notice of Internet Availability of Proxy Materials" and would like to receive a printed copy of our proxy materials, free of charge, you should follow the instructions for requesting such materials below.

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 and do not participate in the electronic delivery of proxy materials will receive only one copy of our Proxy Statement and Annual Report, unless one or more of the shareholders at that address notifies us that they wish to continue receiving individual copies. We believe this procedure provides greater convenience to our shareholders and saves money by reducing our printing and mailing costs and fees.

If you prefer to receive a separate copy of our combined Proxy Statement and Annual Report, please write to Shareholder Relations, Progress Energy, 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 of each 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 telephone, mail, e-mail or other electronic media or personally by our and our subsidiaries' officers and employees, who will not be specially compensated for such services. In addition, the Company will engage Phoenix Advisory Partners, if necessary, to assist in the solicitation of proxies on behalf of the Board. It is anticipated that the cost of the solicitation services to the Company will be approximately $50,000, plus out-of-pocket expenses.

You may vote shares either in person or by duly authorized proxy. In addition, you may vote your shares by telephone or via the Internet by following the instructions provided on the enclosed proxy card. Please be aware that if you vote via the Internet, you may incur costs such as telecommunication and Internet access charges for which you will be responsible. The Internet and telephone voting facilities for shareholders of record will close at 12:01 a.m. E.D.T. on the morning of the meeting. Any shareholder who has executed a proxy and attends the meeting may elect to vote in person 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 and electing to vote in person. Your attendance at the Annual Meeting, by itself, will not constitute a revocation of a proxy. If you vote by telephone or via the Internet, 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 or via the Internet. 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 by accessing the Internet. You should address any written notices of proxy revocation to: Progress Energy, 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; **"FOR"** the option of one year for the frequency of the advisory "nonbinding" vote on 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, 2011, 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.

If you are a participant in our 401(k) Savings & Stock Ownership Plan, shares allocated to your Plan account will be voted by the Trustee only if you execute and return your proxy, or vote by telephone or via the Internet. Plan participants must provide voting instructions on or before 11:59 p.m. E.D.T. on May 11, 2011.

If you are a participant in the Savings Plan for Employees of Florida Progress Corporation (the "FPC Savings Plan"), shares allocated to your Plan account will be voted by the Trustee when you execute and return your proxy, or vote by telephone or via the Internet. If no direction is given, your shares will be voted in proportion with the shares held in the FPC Savings Plan and in the best interest of the FPC Savings Plan.

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 vote in person at the 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 Progress Energy shares on your behalf may vote the shares at its discretion with regard to "routine" matters. However, such brokerage firm, bank or other nominee is not required to vote the shares of Common Stock, 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"), including the New York Stock Exchange ("NYSE"), to vote its clients' shares if the clients do not provide instructions. When a brokerage firm, bank or other nominee votes its clients' Common Stock shares 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 NYSE recently 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 2011 Annual Meeting of Shareholders, the following three nonroutine matters will be presented for a vote: the election of 14 directors of the Company with terms expiring in 2012; an advisory (nonbinding) vote on executive compensation; and an advisory (nonbinding) vote to determine whether the vote on executive compensation will occur every one, two or three years.

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 4, 2011, as the record date for shareholders entitled to vote at the Annual Meeting. Only holders of our Common Stock 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 4, 2011, there were outstanding 293,558,966 shares of 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 Common Stock shares entitled to vote is necessary to constitute a quorum for the transaction of business at the Annual Meeting. Once a share of Common Stock 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. Common Stock shares held of record by shareholders or their nominees who do not vote by proxy or attend the Annual Meeting in person 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 our Articles of Incorporation, as amended effective May 10, 2006, a candidate for director will be elected upon receipt of at least a majority of the votes cast by the holders of Common Stock entitled to vote. Accordingly, assuming a quorum is present, each director shall be elected by a vote of the majority of the votes cast with respect to that director. A majority of the votes cast means that the number of shares voted **"FOR"** a director must exceed the number of votes cast **"AGAINST"** that director. Shares voting **"ABSTAIN"** and 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.

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 holders of Common Stock 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 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 any such matters.

With regard to the advisory (nonbinding) proposal to determine whether the frequency vote to approve executive compensation will occur every one, two or three years, assuming a quorum is present, the option of once every year, two years or three years that receives the highest number of **"FOR"** votes cast at the meeting will be the frequency option for the advisory (nonbinding) vote on the compensation of our named executive officers that is approved on an advisory basis. 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.

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 Common Stock 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 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 any such matters.

We will announce preliminary voting results at 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. In addition, we will disclose the decision about how frequently the Company will conduct future votes on executive compensation in a Current Report on Form 8-K within 150 calendar days of our Annual Meeting, but no later than October 3, 2011. A copy of these Forms 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, as amended.

PROPOSAL 1—ELECTION OF DIRECTORS

The Company's amended By-Laws provide that the number of directors of the Company shall be between eleven (11) and fifteen (15). The amended By-Laws also provide for annual elections of each director. Directors will serve one-year terms upon election at the 2011 Annual Meeting of Shareholders.

Our Articles of Incorporation require that a candidate in an uncontested election for director receive a majority of the votes cast in order to be elected as a director (i.e., the number of votes cast **"FOR"** a director must exceed the number of votes cast **"AGAINST"** that director). In a contested election (i.e., a situation in which the number of nominees exceeds the number of directors to be elected), the standard for election of directors will be a plurality of the votes cast. Under North Carolina law, a director continues to serve in office until his or her successor is elected or until there is a decrease in the number of directors, even if the director is a candidate for re-election and does not receive the required vote, referred to as a "holdover director." To address the potential for such a "holdover director," our Board of Directors approved a provision in our Corporate Governance Guidelines. That provision states that if an incumbent director is nominated, but not re-elected by a majority vote, the director shall tender his or her resignation to the Board. The Corporate Governance Committee (the "Governance Committee") would then make a recommendation to the Board about whether to accept or reject the resignation. The Board will act on the Governance Committee's recommendation and publicly disclose its decision and the rationale regarding it within 90 days after receipt of the tendered resignation. Any director who tenders his or her resignation pursuant to this provision shall not participate in the Governance Committee's recommendation or Board of Directors' action regarding the acceptance of the resignation offer. However, if all members of the Governance Committee do not receive a vote sufficient for re-election, then the independent directors who did not fail to receive a sufficient vote shall appoint a committee among themselves to consider the resignation offers and recommend to the Board of Directors whether to accept them. If the only directors who did not fail to receive a sufficient vote for re-election constitute three or fewer directors, all directors may participate in the action regarding whether to accept the resignation offers.

Based on the report of the Governance Committee (see page 17), the Board of Directors nominates the following 14 nominees to serve as directors with terms expiring in 2012 and until their respective successors are elected and qualified: John D. Baker II, James E. Bostic, Jr., Harris E. DeLoach, Jr., James B. Hyler, Jr., William D. Johnson, Robert W. Jones, W. Steven Jones, Melquiades R. "Mel" Martinez, E. Marie McKee, John H. Mullin, III, Charles W. Pryor, Jr., Carlos A. Saladrigas, Theresa M. Stone, and Alfred C. Tollison, Jr.

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 majority of the votes cast at the Annual Meeting at which a quorum is present. This means that the number of votes cast **"FOR"** a director must exceed the number of votes cast **"AGAINST"** that director in order for the director to 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 14 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 Board of Directors, acting through the Governance Committee, is responsible for assembling for shareholder consideration a group of nominees that, taken together, have the experience, qualifications, attributes and skills appropriate for functioning effectively as a board. The Governance Committee regularly reviews the composition of the Board in light of the Company's changing requirements and its assessment of the Board's performance. A discussion of the characteristics the Governance Committee looks for in evaluating director candidates appears in the "Governance Committee Process for Identifying and Evaluating Director Candidates" section on page 19 of this Proxy Statement.

The names of the 14 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 individual should serve on the Board, are set forth below. (Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC") and Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), which are noted below, are wholly owned subsidiaries of the Company.) Information concerning the number of shares of our Common Stock beneficially owned, directly or indirectly, by all current directors appears on page 11 of this Proxy Statement.

The Board of Directors recommends a vote **"FOR"** each nominee for director.

Nominees for Election

JOHN D. BAKER II, age 62, is Executive Chairman of Patriot Transportation Holding, Inc., which is engaged in the transportation and real estate businesses, since October 2010. He served as President and Chief Executive Officer of Patriot Transportation Holding from February 2008 to October 2010. Mr. Baker was President and Chief Executive Officer of Florida Rock Industries, Inc., a producer of cement, aggregates, concrete and concrete products, from 1997 to 2007. As a lawyer and business executive with more than 35 years of experience in the construction materials and trucking industries, Mr. Baker brings to the Board business insight and expertise that are valuable to the Company as it navigates a complex and changing business environment. He has first-hand knowledge of the economic and business development issues facing companies in the State of Florida. Mr. Baker's executive experience and service on the boards of other public companies have prepared him to respond to financial and operational challenges and have enhanced his ability to work effectively with other directors, understand board processes and functions, and oversee management. **Mr. Baker has served as a director of the Company since 2009. He is a member of the Board's Finance Committee and the Organization and Compensation Committee.**

Other public directorships in past five years:
Patriot Transportation Holding, Inc. (1986 to present)
Wells Fargo & Company (January 2009 to present)
Texas Industries, Inc. (October 2010 to present)
Vulcan Materials Co. (November 2007 until February 2009)
Wachovia Bank, N.A. (2001 until December 2008)
Florida Rock Industries, Inc. (1979 until November 2007)
Hughes Supply, Inc. (1994 until 2006)

JAMES E. BOSTIC, JR., age 63, has been Managing Director of HEP & Associates, a business consulting firm, and a partner of Coleman Lew & Associates, an executive search consulting firm, since 2006. He retired as Executive Vice President of Georgia-Pacific Corporation, a manufacturer and distributor of tissue, paper, packaging, building products, pulp and related chemicals, in 2006. During his 20 years at Georgia-Pacific, Mr. Bostic served in various senior positions, including service as Senior Vice President–Environmental, Government Affairs and Communications. Mr. Bostic's business background and his expertise on environmental and regulatory issues are significant assets to the Company and the Board of Directors. That expertise will be particularly helpful as we continue to address new laws and regulations regarding alternative and renewable energy, emission reductions and other environmental issues. Additionally, as a result of his extensive service on the Board, Mr. Bostic has developed a keen understanding of how the Company operates, the key issues it faces, and the Company's strategy for addressing those issues as it carries out its responsibilities to its shareholders and other stakeholders. **Mr. Bostic has served as a director of the Company since 2002. He is a member of the Board's Audit and Corporate Performance Committee, the Nuclear Project Oversight Committee and the Operations and Nuclear Oversight Committee.**

HARRIS E. DELOACH, JR., age 66, is Chairman and Chief Executive Officer of Sonoco Products Company, a manufacturer of paperboard and paper and plastic packaging products, since December 2010. He served as Chairman, President and Chief Executive Officer of Sonoco Products from April 2005 to December, 2010, and as President and Chief Executive Officer from July 2000 to April 2005. Mr. DeLoach joined Sonoco Products in 1986 and has served in various management positions during his tenure there. Prior to joining Sonoco, Mr. DeLoach was in private law practice and served as an outside counsel to Sonoco for 15 years. As a business leader in the State of South Carolina, Mr. DeLoach has first-hand knowledge of the economic and business development issues facing the communities we serve. Mr. DeLoach's legal background and years of experience leading a global packaging company are valuable to the Company as it undertakes the long-range projects and initiatives necessary to optimize its balanced solution strategy for meeting its customers' future energy needs and complying with public policies while creating long-term value in a challenging economy and changing business environment. **Mr. DeLoach has served as a director of the Company since 2006. He is Chair of the Board's Operations and Nuclear Oversight Committee and a member of the Executive Committee, the Governance Committee, the Nuclear Project Oversight Committee and the Organization and Compensation Committee.**

Other public directorships in past five years:
Sonoco Products Company (1998 to present)
Goodrich Corporation (2001 to present)

JAMES B. HYLER, JR., age 63, retired as Vice Chairman and Chief Operating Officer of First Citizens Bank in 2008. He served in these positions from 1994 until 2008. Mr. Hyler was President of First Citizens Bank from 1988 to 1994, and served as Chief Financial Officer of First Citizens Bank from 1980 to 1988. Prior to joining First Citizens Bank, Mr. Hyler was an auditor with Ernst & Young for 10 years. He has more than 37 years of experience in the financial services industry. Mr. Hyler's knowledge and expertise in financial services and corporate finance provide him with the skills needed to assist the Board in its analysis and decision making regarding financial matters as our utilities continue to move forward with the long-range projects and initiatives necessary to optimize our balanced solution strategy for meeting our customers' future energy needs and complying with public policy while creating long-term value in a challenging economy and changing business environment. **Mr. Hyler has served as a director of the Company since 2008. He is a member of the Board's Finance Committee and the Organization and Compensation Committee.**

Other public directorships in past five years:
First Citizens BancShares (August 1988 until January 2008)

WILLIAM D. JOHNSON, age 57, is Chairman, President and Chief Executive Officer of Progress Energy, since October 2007. Mr. Johnson is also Chairman of PEC and PEF. Mr. Johnson 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, Mr. Johnson 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' future energy needs in the face of a challenging economy, and a changing regulatory and legislative environment. **Mr. Johnson is Chair of the Board's Executive Committee.**

ROBERT W. JONES, age 60, is the sole owner of Turtle Rock Group, LLC, founded in May 2009. From 1974 until May 2009, Mr. Jones held various management positions at Morgan Stanley, a global provider of financial services to companies, governments and investors. He served as a Senior Advisor from 2006 until May 2009, and as Managing Director and Vice Chairman from 1997 until 2006. While at Morgan Stanley, Mr. Jones specialized in the utility industry for many years before being named Vice Chairman. Turtle Rock Group, LLC is a financial advisory consulting firm whose sole current client is Morgan Stanley. During his career, Mr. Jones has participated in many major international and domestic utility and project financing transactions, with a particular focus on strategic advisory and capital-raising assignments. He has testified before numerous state public utility commissions and has been a frequent speaker on regulatory and corporate governance issues. Mr. Jones's expertise in financial services and his experience in the regulatory arena provide him with a unique perspective that will be beneficial to the Company as it undertakes the long-range projects and initiatives necessary to optimize its balanced solution strategy for meeting its customers' future energy needs in a challenging economy and uncertain regulatory environment. **Mr. Jones has served as a director of the Company since 2007. He is Chair of the Board's Finance Committee and a member of the Executive Committee, the Governance Committee and the Organization and Compensation Committee.**

W. STEVEN JONES, age 59, is Dean (Emeritus) and Professor of Strategy and Organizational Behavior at the Kenan-Flagler Business School at the University of North Carolina at Chapel Hill, since 2008. He served as Dean of the Kenan-Flagler Business School from August 2003 until August 2008. Prior to joining the Kenan-Flagler Business School in 2003, Mr. Jones had a 30-year career in business. That career included serving as Chief Executive Officer and Managing Director of Suncorp-Metway Ltd., which provides banking, insurance and investing services in Brisbane, Queensland, Australia. He also worked for ANZ, one of Australia's four major banks, in various capacities for eight years. Mr. Jones has international experience in developing strategy, leading change and building organizational capability in a variety of industries. His expertise in the financial services arena continues to be beneficial as the Company undertakes the long-range projects and initiatives necessary to optimize its balanced solution strategy for meeting its customers' future energy needs and complying with public policies while creating long-term value in a challenging economy and changing business environment. **Mr. Jones has served as a director of the Company since 2005. He is a member of the Board's Audit and Corporate Performance Committee, the Nuclear Project Oversight Committee and the Operations and Nuclear Oversight Committee.**

Other public directorships in past five years:
Premiere Global Services, Inc. (2007 to present)
State Farm Mutual Automobile Insurance Co. (June 2010 to present)
Bank of America (April 2005 until April 2008)

MELQUIADES R. "MEL" MARTINEZ, age 64, is a Managing Director of JPMorgan Chase & Co., since August 2010. Mr. Martinez has had a distinguished career in both the public and private sectors, most recently as partner in the law firm of DLA Piper in its Orlando, Florida office from September 2009 to July 2010 and as a United States Senator from Florida from 2005 to 2009. While serving in the U.S. Senate, he addressed multiple policy and legislative issues as a member of the following Senate committees: Armed Services; Banking, Housing & Urban Affairs; Foreign Relations; Energy and Natural Resources; Commerce; and Special Committee on Aging. Prior to his election, Mr. Martinez served as the Secretary of Housing and Urban Development from 2001 to 2004. His extensive legal, policy and legislative experience will be valuable to the Company as we address new laws and regulations in areas such as environmental compliance, renewable energy standards and energy policy. Prior to representing the State of Florida in the U.S. Senate, Mr. Martinez served as Mayor of Orange County, Florida, and as a board member of the Orlando Utilities Commission. He also spent over 25 years in private legal practice, conducting numerous trials in state and federal courts throughout Florida. As a resident and public servant of the State of Florida, Mr. Martinez brings to our Board a unique perspective and first-hand knowledge that continues to be beneficial as we address key regulatory issues in that state. Mr. Martinez's diversified experience and background are significant assets to our Company's Board. **Mr. Martinez has served as a director of the Company since March 1, 2010. He is a member of the Operations and Nuclear Oversight Committee and the Organization and Compensation Committee.**

E. MARIE MCKEE, age 60, is President of the Corning Museum of Glass, since 1998, and served as Senior Vice President of Corning Incorporated, a manufacturer of components for high-technology systems for consumer electronics, mobile emissions controls, telecommunications and life sciences, from 1996 to 2010. Ms. McKee has over 30 years of experience at Corning, where she held a variety of positions with increasing levels of responsibility. She initially served in various human resources manager positions including Human Resources Director for Corning's Electronics Division, its Research & Development Division and its Centralized Engineering Division. While serving in these positions, Ms. McKee gained significant experience in designing and implementing human resources strategies, business processes and organizational change efforts. She then served in various management positions, including Division Vice President of Corporate Strategic Staffing, Vice President, Human Resources and Senior Vice President, Human Resources and Corporate Diversity Officer. Ms. McKee served as Chairman of Steuben Glass from 1998 until the company was sold in 2008. During her tenure on the Board, Ms. McKee's business experience and perspective have proven valuable to the Company as it has addressed various operational and human resources issues. Ms. McKee's depth of experience has provided her with a thorough knowledge of employment and compensation practices and strategies that enables her to assist the Organization and Compensation Committee and the Board in its analysis and decision making regarding executive compensation, succession planning, diversity and other matters. Her experience will continue to be beneficial to the Company as shareholders, regulators and legislators continue to focus on executive compensation and corporate governance issues. **Ms. McKee has served as a director of the Company and its predecessors since 1999. She is Chair of the Board's Organization and Compensation Committee and a member of the Executive Committee, the Governance Committee, the Nuclear Project Oversight Committee and the Operations and Nuclear Oversight Committee.**

JOHN H. MULLIN, III, age 69, is Chairman of Ridgeway Farm, LLC, a limited liability company engaged in farming and timber management, since 1989. He is a former Managing Director of Dillon, Read & Co., a former investment banking firm. Mr. Mullin was employed by Dillon Read for approximately 20 years. During that time, he worked with a diversified mix of clients and was involved in a variety of corporate assignments, including private and public offerings, and corporate restructurings. Since 1989, Mr. Mullin has managed the diversified businesses of Ridgeway Farm. He has served on the boards of a number of other major publicly traded companies, providing him with substantial experience in the areas of corporate strategy, oversight and governance. Mr. Mullin's executive and board experience have enabled him to develop the skills needed to work effectively with other directors, understand board processes and functions, and oversee management. Additionally, as a result of his many years of service on the Board, Mr. Mullin has developed a keen understanding of the Company's operations, the key issues it faces and the Company's strategy for addressing those issues as it carries out its responsibilities to its shareholders and other stakeholders. He has effectively utilized his broad and extensive business experiences and knowledge of the Company to provide leadership to the Company's Board as Lead Director. **Mr. Mullin has served as a director of the Company and its predecessors since 1999. He is Chair of the Board's Governance Committee and a member of the Executive Committee, the Finance Committee and the Organization and Compensation Committee.**

Other public directorships in past five years:
Sonoco Products Company (2002 to present)
Hess Corporation (2007 to present)
Liberty Corporation (1989 until 2006)
Putnam Funds – Trustee (1997 until 2006)

CHARLES W. PRYOR, JR., age 66, is Chairman of Urenco USA Inc. (formerly Urenco Investments, Inc.), a global provider of services and technology to the nuclear generation industry worldwide, since January 2007. He served as President and Chief Executive Officer of Urenco Investments, Inc. from 2004 to 2006. Mr. Pryor served as President and Chief Executive Officer of the Utilities Business Group of British Nuclear Fuels from 2002 to 2004. From 1997 to 2002, he served as President and Chief Executive Officer of Westinghouse Electric Co., a supplier of nuclear fuel, nuclear services and advanced nuclear plant designs to utilities operating nuclear power plants. Mr. Pryor's former service as chief executive officer of a multi-billion dollar company provides him with experience that enables him to understand the financial statements and financial affairs of the Company. He has extensive experience in managing capital-intensive industries and skillfully addressing regulatory matters, strategic planning and corporate development. Mr. Pryor's knowledge and experience in engineering, power generation, nuclear fuel and the utility industry will be tremendous assets to the Board in the years ahead as our Company executes its plan to improve the performance of its nuclear fleet and optimizes its balanced solution strategy for meeting its customers' future energy needs and complying with public policies while creating long-term value in a challenging economy and a changing business environment. **Mr. Pryor has served as a director of the Company since 2007. He is Chair of the Board's Nuclear Project Oversight Committee and a member of the Audit and Corporate Performance Committee and the Operations and Nuclear Oversight Committee.**

Other public directorships in past five years:
DTE Energy Co. (1999 to present)

CARLOS A. SALADRIGAS, age 62, is Chairman and Chief Executive Officer of Regis HRG, which offers a full suite of outsourced human resources services to small and mid-sized businesses. He has served in these positions since July 2008. Mr. Saladrigas served as Vice Chairman, from 2007 to 2008, and Chairman, from 2002 to 2007, of Premier American Bank in Miami, Florida. In 2002, Mr. Saladrigas retired as Chief Executive Officer of ADP Total Source (previously the Vincam Group, Inc.), a Miami-based human resources outsourcing company that provides services to small and mid-sized businesses. Mr. Saladrigas has extensive expertise in both the human resources and financial services arenas. His accounting background provides him with an understanding of the principles used to prepare the Company's financial statements and enables him to effectively analyze those financial statements. Mr. Saladrigas is a resident of Florida and is familiar with the economic policy issues facing that state. As a result of his years of service on the Board, Mr. Saladrigas has gained institutional knowledge about the Company and its operations. His unique perspective and business acumen will continue to be valuable assets to the Board as the Company executes its plans to optimize its balanced solution strategy for meeting customer needs and complying with public policies while creating long-term value in a challenging economy and a changing business environment. **Mr. Saladrigas has served as a director of the Company since 2001. He is a member of the Board's Audit and Corporate Performance Committee and the Finance Committee. Mr. Saladrigas is one of the Board's two designated Audit Committee Financial Experts.**

Other public directorships in past five years:
Advance Auto Parts, Inc. (2003 to present)

THERESA M. STONE, age 66, has been Executive Vice President and Treasurer of the Massachusetts Institute of Technology Corporation ("M.I.T."), since February 2007. In her role as Executive Vice President and Treasurer, Ms. Stone is responsible for M.I.T.'s capital programs, facilities, human resources and information technology, and serves as M.I.T.'s Chief Financial Officer and Treasurer. From November 2001 to March 2006, Ms. Stone served as Executive Vice President and Chief Financial Officer of Jefferson-Pilot Financial (now Lincoln Financial Group). Ms. Stone began her career as an investment banker, advising clients primarily in the financial services industry on financial and strategic matters and has held senior financial executive officer positions at various companies since that time. Ms. Stone's knowledge and expertise in finance make her uniquely qualified to understand and effectively analyze the Company's financial statements. Her depth of experience in finance and management provide her with the skills needed to assist the Board in its analysis and decision making regarding financial matters as the Company undertakes the long-range projects and initiatives necessary to optimize its balanced solution strategy for meeting its customers' future energy needs and complying with public policies while creating long-term value in a challenging economy and a changing business environment. **Ms. Stone has served as a director of the Company since 2005. She is Chair of the Board's Audit and Corporate Performance Committee and a member of the Executive Committee, the Finance Committee and the Governance Committee. Ms. Stone is one of the Board's two designated Audit Committee Financial Experts.**

ALFRED C. TOLLISON, JR., age 68, retired as Chairman and Chief Executive Officer of the Institute of Nuclear Power Operations ("INPO"), a nuclear industry-sponsored nonprofit organization, in March 2006. He was employed by INPO from 1987 until March 2006. During his tenure there, Mr. Tollison's responsibilities included industry and government relations, communications, information systems and administrative activities. He also served as the executive director of the National Academy for Nuclear Training. From 1970 until 1987, Mr. Tollison was employed by PEC, where he served in a variety of management positions, including plant general manager of the Brunswick Nuclear Plant and manager of nuclear training. His management experience as a chief executive officer of a large nonprofit entity in the energy industry, as well as his in-depth knowledge of that industry, enables him to bring a unique perspective to the Company's Board. Mr. Tollison's track record and expertise in promoting the safe and reliable operations of our nation's nuclear generating plants will continue to be a significant asset to our Board as the Company executes its plan for improving the performance of its nuclear fleet and optimizes its balanced solution strategy for meeting the future energy needs of its customers safely, reliably and affordably. **Mr. Tollison has served as a director of the Company since 2006. He is Vice Chair of the Board's Nuclear Project Oversight Committee and a member of the Audit and Corporate Performance Committee and the Operations and Nuclear Oversight Committee. Mr. Tollison also serves as the Nuclear Oversight Director.**

PRINCIPAL SHAREHOLDERS

The table below sets forth the only shareholder we know to beneficially own more than 5 percent (5%) of the outstanding shares of our Common Stock as of December 31, 2010. We do not have any other class of voting securities.

Title of Class	Name and Address of Beneficial Owner	Number of Shares Beneficially Owned	Percentage of Class
Common Stock	State Street Corporation One Lincoln Street Boston, MA 02111	26,315,197[1]	9.0

[1] Consists of shares of Common Stock held by State Street Corporation, acting in various fiduciary capacities. State Street Corporation has sole power to vote with respect to 0 shares, sole dispositive power with respect to 0 shares, shared power to vote with respect to 26,315,197 shares and shared power to dispose of 26,315,197 shares. State Street Corporation has disclaimed beneficial ownership of all shares of Common Stock. (Based solely on information contained in a Schedule 13G filed by State Street Corporation on February 11, 2011.)

MANAGEMENT OWNERSHIP OF COMMON STOCK

The following table describes the beneficial ownership of our Common Stock as of February 28, 2011, 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 28, 2011, none of the individuals or the group in the above categories owned one percent (1%) or more of our voting securities. Unless otherwise noted, all shares of 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[1,2]
John D. Baker II	7,450
James E. Bostic, Jr.	8,569[1]
Harris E. DeLoach, Jr.	5,000
James B. Hyler, Jr.	1,000
William D. Johnson	204,278[2]
Robert W. Jones	1,000
W. Steven Jones	1,000
Jeffrey J. Lyash	24,930[2]
Melquiades R. "Mel" Martinez	500
John R. McArthur	66,718[2]
E. Marie McKee	3,000[1]
Mark F. Mulhern	50,874[2]
John H. Mullin, III	10,000[1]
Charles W. Pryor, Jr.	1,042
Carlos A. Saladrigas	7,000[1]
Theresa M. Stone	1,000
Alfred C. Tollison, Jr.	1,000
Lloyd M. Yates	48,784[2]
Shares of Common Stock beneficially owned by all directors and executive officers of the Company as a group (24 persons)	614,533[3]

[1] Includes shares of our Common Stock such director has the right to acquire beneficial ownership of within 60 days through the exercise of certain stock options, as follows:

Director	Stock Options
James E. Bostic, Jr.	4,000
E. Marie McKee	2,000
John H. Mullin, III	6,000
Carlos A. Saladrigas	6,000

[2] Includes shares of Restricted Stock currently held, and shares of our Common Stock such officer has the right to acquire beneficial ownership of within 60 days through the exercise of certain stock options, as follows:

Officer	Restricted Stock	Stock Options
William D. Johnson	5,534	—
Jeffrey J. Lyash	1,367	—
John R. McArthur	1,667	—
Mark F. Mulhern	1,167	7,000
Lloyd M. Yates	1,367	—

[3] Includes shares each group member (shares in the aggregate) has the right to acquire beneficial ownership of within 60 days through the exercise of certain stock options.

Ownership of Units Representing Common Stock

The table below shows ownership of units representing our Common Stock under the Non-Employee Director Deferred Compensation Plan and units under the Non-Employee Director Stock Unit Plan as of February 28, 2011. A unit of Common Stock does not represent an equity interest in the Company, and possesses no voting rights, but is equal in economic value at all times to one share of Common Stock.

Director	Directors' Deferred Compensation Plan	Non-Employee Director Stock Unit Plan
John D. Baker II	3,884	2,971
James E. Bostic, Jr.	13,594	11,999
Harris E. DeLoach, Jr.	13,652	7,734
James B. Hyler, Jr.	2,305	4,665
Robert W. Jones	10,436	6,198
W. Steven Jones	15,111	9,357
Melquiades R. "Mel" Martinez	1,365	1,395
E. Marie McKee	31,748	15,026
John H. Mullin, III	21,494	15,552
Charles W. Pryor, Jr.	3,017	6,198
Carlos A. Saladrigas	8,148	13,053
Theresa M. Stone	12,015	9,357
Alfred C. Tollison, Jr.	13,186	7,734

The table below shows ownership as of February 28, 2011, of (i) performance units under the Long-Term Compensation Program; (ii) performance units recorded to reflect awards deferred under the Management Incentive Compensation Plan ("MICP"); (iii) performance shares awarded under the Performance Share Sub-Plan of the 1997, 2002 and 2007 Equity Incentive Plans ("PSSP") (see "Outstanding Equity Awards at Fiscal Year-End Table" on page 53); (iv) units recorded to reflect awards deferred under the PSSP; (v) replacement units representing the value of our contributions to the 401(k) Savings & Stock Ownership Plan that would have been made but for the deferral of salary under the Management Deferred Compensation Plan and contribution limitations under Section 415 of the Internal Revenue Code of 1986, as amended; and (vi) Restricted Stock Units ("RSUs") awarded under the 2002 and 2007 Equity Incentive Plans.

Officer	Long-Term Compensation Program	MICP	PSSP	PSSP Deferred	MDCP	RSUs
William D. Johnson	—	1,812	122,314	—	1,121	66,714
Jeffrey J. Lyash	—	—	28,446	—	3,726	16,192
John R. McArthur	—	—	30,665	—	—	16,632
Mark F. Mulhern	—	1,808	25,611	911	—	14,558
Lloyd M. Yates	—	2,829	28,129	6,749	168	16,087

CHANGES IN CONTROL

On January 8, 2011, Duke Energy Corporation ("Duke Energy") and Progress Energy entered into a Merger Agreement, pursuant to which Progress Energy will be acquired by Duke Energy in a stock-for-stock transaction and continue as a wholly owned subsidiary of Duke Energy (the "Proposed Merger"). Both companies' boards of directors have unanimously approved the Merger Agreement. However, consummation of the Proposed Merger is subject to customary conditions, including, among other things, approval of the shareholders of each company, 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, the South Carolina Public Service Commission, the Florida Public Service Commission, the Indiana Utility Regulatory Commission, and the Ohio Public Utilities Commission.

TRANSACTIONS WITH RELATED PERSONS

There were no transactions in 2010, 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.

Our 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. The Board has determined that the Governance Committee is best suited to review and approve Related Person Transactions because the Governance Committee oversees the Board of Directors' assessment of our directors' independence. The 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 we (including any of our subsidiaries) were, are 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.

Our general policy is to avoid Related Person Transactions. Nevertheless, we recognize 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 only approve 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 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 2010 fiscal year were met, except as previously disclosed in our 2010 Annual Meeting Proxy Statement, dated March 31, 2010, as filed with the SEC.

CORPORATE GOVERNANCE GUIDELINES AND CODE OF ETHICS

The Board of Directors operates pursuant to an established set of written Corporate Governance Guidelines (the "Governance Guidelines") that set forth our corporate governance philosophy and the governance policies and practices we have implemented in support of that philosophy. The three core governance principles the Board embraces are integrity, accountability and independence.

The Governance Guidelines describe Board membership criteria, the Board selection and orientation process and Board leadership. The Governance Guidelines require that a minimum of 80 percent of the Board's members be independent and that the membership of each Board committee, except the Executive Committee, consist solely of independent directors. Directors who are not full-time employees of the Company must retire from the Board at age 73. Directors whose job responsibilities or other factors relating to their selection to the Board change materially after their election are required to submit a letter of resignation to the Board. The Board will have an opportunity to review the continued appropriateness of the individual's Board membership under these circumstances, and the Governance Committee will make the initial recommendation as to the individual's continued Board membership. The Governance Guidelines also describe the stock ownership guidelines that are applicable to Board members and prohibit compensation to Board members other than directors' fees and retainers.

The Governance Guidelines provide that the Organization and Compensation Committee of the Board will evaluate the performance of the Chief Executive Officer on an annual basis, using objective criteria, and will communicate the results of its evaluation to the full Board. The Governance Guidelines also provide that the Governance Committee is responsible for conducting an annual assessment of the performance and effectiveness of the Board, and its standing committees, and reporting the results of each assessment to the full Board annually.

The Governance Guidelines provide that Board members have complete access to our management and can retain, at our expense, independent advisors or consultants to assist the Board in fulfilling its responsibilities, as it deems necessary. The Governance Guidelines also state that it is the Board's policy that the nonmanagement directors meet in executive session on a regularly scheduled basis. Those sessions are chaired by the Lead Director, John H. Mullin, III, who is also Chair of the Governance Committee. He can be contacted by writing to John H. Mullin, III, Lead Director, Progress Energy, Inc. Board of Directors, c/o John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary, P.O. Box 1551, Raleigh, North Carolina 27602-1551. We screen mail addressed to Mr. Mullin for security purposes and to ensure that it relates to discrete business matters relevant to the Company. Mail addressed to Mr. Mullin that satisfies these screening criteria will be forwarded to him.

In keeping with the Board's commitment to sound corporate governance, we have adopted a comprehensive written Code of Ethics that incorporates an effective reporting and enforcement mechanism. The Code of Ethics is applicable to all of our employees, including our Chief Executive Officer, our Chief Financial Officer and our Controller. The Board has adopted the Company's Code of Ethics as its own standard. Board members, our officers and our employees certify their compliance with our Code of Ethics on an annual basis.

Our Governance Guidelines and Code of Ethics are posted on our Internet website and can be accessed at *www.progress-energy.com/investor*.

DIRECTOR INDEPENDENCE

The Board of Directors has determined that the following current members of the Board are independent, as that term is defined under the general independence standards contained in the listing standards of the NYSE:

John D. Baker II	E. Marie McKee
James E. Bostic, Jr.	John H. Mullin, III
Harris E. DeLoach, Jr.	Charles W. Pryor, Jr.
James B. Hyler, Jr.	Carlos A. Saladrigas
Robert W. Jones	Theresa M. Stone
W. Steven Jones	Alfred C. Tollison, Jr.
Melquiades R. "Mel" Martinez	

In addition to considering the NYSE's general independence standards, the Board has adopted categorical standards to assist it in making determinations of independence. The Board's categorical independence standards are outlined in our Governance Guidelines. The Governance Guidelines are available on our Internet website and can be accessed at *www.progress-energy.com/investor*. All directors and director nominees identified as independent in this Proxy Statement meet these categorical standards.

In determining that the individuals named above are or were independent directors, the Governance Committee considered their involvement in various ordinary course commercial transactions and relationships during 2010 as described below:

- Messrs. DeLoach and Mullin and Ms. McKee served as officers and/or directors of companies that have been among the purchasers of the largest amounts of electric energy sold by PEC during the last three preceding calendar years. These transactions involve the rendering of services by a public utility at rates fixed in conformity with governmental authorities.
- Messrs. Baker, Hyler, W. Steven Jones and Saladrigas served as directors of companies that purchase electric energy from PEC, and Messrs. Baker, W. Steven Jones, Mullin and Saladrigas served as directors of companies that purchase electric energy from PEF. These transactions involve the rendering of services by public utilities at rates fixed in conformity with governmental authorities.
- Mr. Baker currently serves as a director of Wells Fargo & Company and is a former director of Wachovia Corporation. Both of these entities have been part of our core bank group and have provided a variety of banking and investment services to us during the past several years.
- Mr. W. Steven Jones serves as a director of a communications technology company that provided services to us in 2010.
- Mr. Martinez is a Managing Director of JPMorgan Chase & Co., which has provided a variety of investment banking services to us during the past several years.
- Mr. Pryor is a director of a company that has affiliates that provide uranium enrichment services to PEC and PEF.
- Mr. Tollison is a former employee of PEC and thus receives a modest pension from us.

All of the described transactions were ordinary course commercial transactions conducted at arm's length and in compliance with the NYSE's standards for director independence. In addition, the Governance Committee considers the relationships our directors have with tax-exempt organizations that receive contributions from the Company. The Governance Committee considered each of these transactions and relationships and determined that none of them was material or affected the independence of the directors involved under either the general independence standards contained in the NYSE's listing standards or our categorical independence standards.

BOARD, BOARD COMMITTEE AND ANNUAL MEETING ATTENDANCE

The Board of Directors is currently comprised of fourteen (14) members. The Board of Directors met 10 times in 2010. Average attendance of the directors at the meetings of the Board and its committees held during 2010 was 96 percent, and no director attended less than 87 percent of all Board and his/her respective committee meetings held in 2010.

Our Company expects all directors to attend its annual meetings of shareholders. Such attendance is monitored by the Governance Committee. All directors who were serving as directors as of May 12, 2010, the date of the 2010 Annual Meeting of Shareholders, attended that meeting.

BOARD COMMITTEES

The Board of Directors appoints from its members an Executive Committee, an Audit and Corporate Performance Committee, a Governance Committee, a Finance Committee, a Nuclear Project Oversight Committee, an Operations and Nuclear Oversight Committee, and an Organization and Compensation Committee. The charters of all committees of the Board are posted on our Internet website and can be accessed at *www.progress-energy.com/investor*. The current membership and functions of the standing Board committees are discussed below.

Executive Committee

The Executive Committee is presently composed of one director who is an officer and five nonmanagement directors: Messrs. William D. Johnson—Chair, Harris E. DeLoach, Jr., Robert W. Jones, and John H. Mullin, III, Ms. E. Marie McKee, and Ms. Theresa M. Stone. The authority and responsibilities of the Executive Committee are described in our By-Laws. Generally, the Executive Committee will review routine matters that arise between meetings of the full Board and require action by the Board. The Executive Committee did not meet in 2010.

Audit and Corporate Performance Committee

The Audit and Corporate Performance Committee (the "Audit Committee") is presently composed of the following six nonmanagement directors: 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. All members of the committee are independent as that term is defined under the enhanced independence standards for audit committee members contained in the Securities Exchange Act of 1934 and the related rules, as amended, as incorporated into the listing standards of the NYSE. Mr. Saladrigas and Ms. Stone have been designated by the Board as the "Audit Committee Financial Experts," as that term is defined in the SEC's rules. The work of the Audit Committee includes oversight responsibilities relating to the integrity of our financial statements, compliance with legal and regulatory requirements, the qualifications and independence of our independent registered public accounting firm, performance of the internal audit function and of the independent registered public accounting firm, and the Corporate Ethics Program. The role of the Audit Committee is further discussed under "Report of the Audit and Corporate Performance Committee" below. The Audit Committee held seven meetings in 2010.

Corporate Governance Committee

The Governance Committee is presently composed of the following five nonmanagement directors: Messrs. John H. Mullin, III—Chair/Lead Director, Harris E. DeLoach, Jr., and Robert W. Jones, Ms. E. Marie McKee, and Ms. Theresa M. Stone. All members of the Governance Committee are independent as that term is defined under the general independence standards contained in the NYSE listing standards. The Governance Committee is responsible for making recommendations to the Board with respect to the governance of the Company and the Board. Its responsibilities include recommending amendments to our Charter and By-Laws; making recommendations regarding the structure, charter, practices and policies of the Board; ensuring that processes are in place for annual Chief Executive Officer performance appraisal and review of succession planning and management development; recommending a process for the annual assessment of Board performance; recommending criteria for Board membership; and reviewing the qualifications of and recommending to the Board nominees for election. The Governance Committee is responsible for conducting investigations into or studies of matters within the scope of its responsibilities and for retaining outside advisors to identify director candidates. The Governance Committee will consider qualified candidates for director nominated by shareholders at an annual meeting of shareholders, provided, however, that written notice of any shareholder nominations must be received by the Corporate Secretary of the Company no 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. See "Future Shareholder Proposals" below for more information regarding shareholder nominations of directors. The Governance Committee held 10 meetings in 2010.

Finance Committee

The Finance Committee is presently composed of the following six nonmanagement directors: Messrs. Robert W. Jones—Chair, John D. Baker II, James B. Hyler, Jr., John H. Mullin, III, and Carlos A. Saladrigas, and Ms. Theresa M. Stone. The Finance Committee reviews and oversees our financial policies and planning, financial position, strategic planning and investments, pension funds and financing plans. The Finance Committee also monitors our risk management activities and financial position and recommends changes to our dividend policy and proposed budget. The Finance Committee held four meetings in 2010.

Nuclear Project Oversight Committee (*ad hoc*)

The Nuclear Project Oversight Committee is presently composed of the following six nonmanagement directors: Messrs. Charles W. Pryor, Jr.—Chair, Alfred C. Tollison, Jr.—Vice Chair, James E. Bostic, Jr., Harris E. DeLoach, Jr., and W. Steven Jones, and Ms. E. Marie McKee. The *ad hoc* Nuclear Project Oversight Committee serves as the primary point of contact for Board oversight of the construction of new nuclear projects, and advises the Board of construction status, including schedule, cost and legal, legislative and regulatory activities. The Nuclear Project Oversight Committee did not meet in 2010.

Operations and Nuclear Oversight Committee

The Operations and Nuclear Oversight Committee is presently composed of the following seven nonmanagement directors: Messrs. Harris E. DeLoach, Jr.—Chair, James E. Bostic, Jr., W. Steven Jones, Melquiades R. "Mel" Martinez, Charles W. Pryor, Jr., and Alfred C. Tollison, Jr., and Ms. E. Marie McKee. The Operations and Nuclear Oversight Committee reviews our load forecasts and plans for generation, transmission and distribution, fuel procurement and transportation, customer service, energy trading and term marketing, and other Company operations. The Operations and Nuclear Oversight Committee reviews and assesses our policies, procedures, and practices relative to the protection of the environment and the health and safety of our employees, customers, contractors and the public. The Operations and Nuclear Oversight Committee advises the Board and makes recommendations for the Board's consideration regarding operational, environmental and safety-related issues. The Operations and Nuclear Oversight Committee held six meetings in 2010.

Organization and Compensation Committee

The Organization and Compensation Committee (the "Compensation Committee") is presently composed of the following seven nonmanagement directors: 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. All members of the Compensation Committee are independent as that term is defined under the general independence standards contained in the NYSE listing standards. The Compensation Committee verifies that personnel policies and procedures are in keeping with all governmental rules and regulations and are designed to attract and retain competent, talented employees and develop the potential of these employees. The Compensation Committee reviews all executive development plans, makes executive compensation decisions, evaluates the performance of the Chief Executive Officer and oversees plans for management succession.

The Compensation Committee may hire outside consultants, and the Compensation Committee has no limitations on its ability to select and retain consultants as it deems necessary or appropriate. Annually, the Compensation Committee evaluates the performance of its compensation consultant to assess its effectiveness in assisting the Committee with implementing the Company's compensation program and principles. For 2010, the Compensation Committee retained Meridian Compensation Partners, LLC ("Meridian") as its executive compensation and benefits consultant to assist the Compensation Committee in meeting its compensation objectives for our Company. Under the terms of its engagement, in 2010, Meridian reported directly to the Compensation Committee.

The Compensation Committee relies on its compensation consultant to advise it on various matters relating to our executive compensation and benefits program. These services include:

- Advising the Compensation Committee on general trends in executive compensation and benefits;
- Summarizing developments relating to disclosure, risk assessment process and other technical areas;
- Performing benchmarking and competitive assessments;
- Assisting in designing incentive plans;
- Performing financial analysis related to plan design and assisting the Compensation Committee in making pay decisions in light of results; and
- Recommending appropriate performance metrics and financial targets.

The Compensation Committee has adopted a policy for Pre-Approval of Compensation Consultant Services (the "Policy"). Pursuant to the Policy, the compensation consultant may not provide any services or products to the Company without the express prior approval of the Compensation Committee. The compensation consultant did not provide any services or products to the Company other than those that are provided to the Committee and that are related to the Company's executive compensation and benefits program.

The Compensation Committee's chair or the chairman of our Board of Directors may call meetings, other than previously scheduled meetings, as needed. The Compensation Committee may form subcommittees for any purpose that the Compensation Committee deems appropriate and may delegate to such subcommittees such power and authority as the Compensation Committee deems appropriate. Appropriate executive officers of the Company ensure that the Compensation Committee receives administrative support and assistance, and make recommendations to the Committee to ensure that compensation plans are aligned with our business strategy and compensation philosophy. John R. McArthur, our Executive Vice President, General Counsel and Corporate Secretary, serves as management's liaison to the Compensation Committee. William D. Johnson, our Chief Executive Officer, is responsible for conducting annual performance evaluations of the other executive officers and making recommendations to the Compensation Committee regarding those executives' compensation.

The Compensation Committee held eight meetings in 2010.

Compensation Committee Interlocks and Insider Participation

None of the directors who served as members of the Compensation Committee during 2010 was our employee or former employee and none of them had any relationship requiring disclosure under Item 404 of Regulation S-K. During 2010, none of our executive officers served on the compensation committee (or equivalent), or the board of directors of another entity whose executive officer(s) served on our Compensation Committee or Board of Directors.

DIRECTOR NOMINATING PROCESS AND COMMUNICATIONS WITH BOARD OF DIRECTORS

Governance Committee

The Governance Committee performs the functions of a nominating committee. The Governance Committee's Charter describes its responsibilities, including recommending criteria for membership on the Board, reviewing qualifications of candidates and recommending to the Board nominees for election to the Board. As noted above, the Governance Guidelines contain information concerning the Committee's responsibilities with respect to reviewing with the Board on an annual basis the qualification standards for Board membership and identifying, screening and recommending potential directors to the Board. All members of the Governance Committee are independent as defined under the general independence standards of the NYSE's listing standards. Additionally, the Governance Guidelines require that all members of the Governance Committee be independent.

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 to the Governance Committee will be acknowledged, in writing, by the Corporate Secretary. The recommendation will be promptly forwarded to the Chair of the Governance Committee, who will place consideration of the recommendation on the agenda for the Governance Committee's regular December meeting. The Governance Committee will discuss candidates recommended by shareholders at its December meeting and present information regarding such candidates, along with the Governance Committee's recommendation regarding each candidate, to the full Board for consideration. The full Board will determine whether it will nominate a particular candidate for election to the Board.

Additionally, in accordance with Section 11 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" below.

Governance Committee Process for Identifying and Evaluating Director Candidates

The Governance Committee evaluates all director candidates, including those nominated or recommended by shareholders, in accordance with the Board's qualification standards, which are described in the Governance Guidelines. The Committee 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; independence as defined under the general independence standards contained in the NYSE listing standards and the categorical standards adopted by the Board; financial acumen; strategic thinking; ability to work effectively as a team member; demonstrated leadership and excellence in a chosen field of endeavor; 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; an understanding of our responsibilities to shareholders, employees, customers and the communities we serve; and service on other boards of directors that would not detract from service on our Board.

Although the Company does not have an official policy regarding the consideration of diversity in identifying director nominees, diversity is among the factors that are considered in selecting Board nominees. The Company values diversity among its Board members and seeks to create a Board that reflects the demographics of the areas we serve, and includes a complementary mix of individuals with diverse backgrounds, viewpoints, professional experiences, education and skills that reflect the broad set of challenges the Board confronts.

Communications with the Board of Directors

The Board has approved a process for shareholders and other interested parties to send communications to the Board. That process provides that shareholders and other interested parties can send communications to the Board and, if applicable, to the Governance Committee or to specified individual directors, including the Lead Director, in writing c/o John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary, Progress Energy, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551.

We screen mail addressed to the Board, the Governance Committee 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 LEADERSHIP STRUCTURE AND ROLE IN RISK OVERSIGHT

Board Leadership Structure

Our Governance Guidelines allow the Board to select a Chairman based on the needs of the Company at the time. The Board may appoint the Chief Executive Officer or it may choose another director for the Chairman position. Thus, the Board has the authority to separate the Chairman and Chief Executive Officer positions if it chooses to do so, but it is not required to do so.

Currently, the Board believes that the Company's interests are best served by having the Chief Executive Officer also serve as Chairman because it allows the Board to most effectively and directly leverage the Chief Executive Officer's day-to-day familiarity with the Company's operations. 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 considered by the Company, including the construction of new nuclear facilities.

Our Governance Guidelines provide that if the Chief Executive Officer currently holds the position of Chairman, then the full Board shall appoint an independent director to serve as Chair of the Governance Committee and Lead Director of the Board. The clearly delineated and comprehensive duties of the Lead Director include presiding over all meetings of the Board at which the Chairman is not present, including executive sessions and other meetings of the non-management and independent directors and serving as liaison and facilitating communication between the independent directors and the Chairman. The Lead Director also provides input to the Chairman and CEO with respect to information sent to the Board and the agendas and schedules for Board and committee meetings. Any independent director, including the Lead Director, has the authority to call meetings of the independent directors. If requested by major shareholders, the Lead Director is available for consultation and direct communication. In addition, the Lead Director serves as a mentor and advisor to the Chairman and Chief Executive Officer and assures that the Chairman and Chief Executive Officer understands the Board's views on critical matters. Pursuant to the Governance Guidelines, Mr. Mullin, an independent director and Chair of the Governance Committee, has served as Lead Director of the Board since 2004.

In our view, our current leadership structure has fostered sound corporate governance practices and strong independent Board leadership that have benefitted the Company and its shareholders.

Board Role in Risk Oversight

We have established a framework that supports the risk management activities that occur across Progress Energy. The framework establishes processes for identifying, measuring, managing and monitoring risk across the Company and its subsidiaries. We also maintain an ongoing oversight structure that details risk types and the internal organizations and Board Committees that have oversight and governance responsibility for each risk type. Our Chief Executive Officer and Senior Management have responsibility for assessing and managing the Company's exposure to risk. In this regard, we have established a Risk Management Committee, comprised of various senior executives, that provides guidance and direction in the identification and management of financial risks. The Board is not involved in the Company's day-to-day risk management activities; however, the 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 the Board of Directors. Because overseeing risk is an ongoing process and inherent in the Company's strategic decisions, the Board also discusses risk throughout the year at other meetings in relation to specific proposed actions.

The Audit and Corporate Performance Committee 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 the Company'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 the Company's compliance with legal and regulatory requirements.

The Finance Committee 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 at least once a quarter.

The Operations and Nuclear Oversight Committee is charged with oversight of risks related to operations, major capital projects and environmental, health and safety issues.

The Organization and Compensation Committee is responsible for the oversight of risks that can result from personnel issues and misalignment between compensation and performance plans and the interests of the Company's shareholders.

Our risk management structure is designed to enable the Board to stay informed about and understand the key risks facing the Company, how those risks relate to the Company's business and strategy, and the steps the Company is taking to manage those risks.

COMPENSATION DISCUSSION AND ANALYSIS

EXECUTIVE SUMMARY

We are an integrated electric utility primarily engaged in the regulated utility business. Our executive compensation philosophy is designed to provide competitive compensation consistent with key principles that we believe are critical to our long-term success.

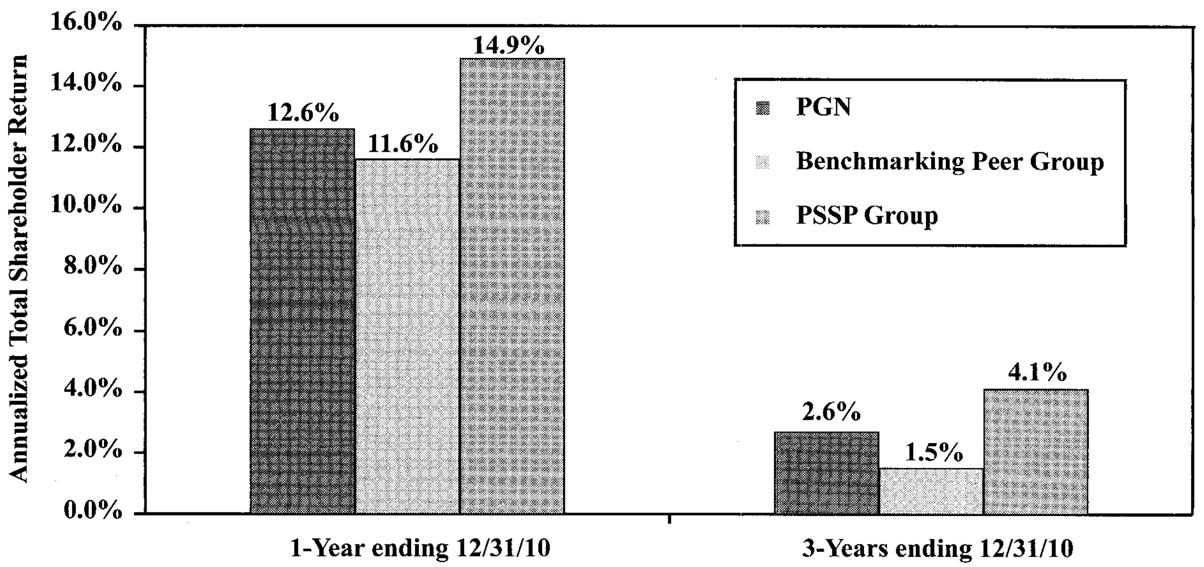
We are committed to providing an executive compensation program that supports the following goals and philosophies:

- Aligning our management team's interests with shareholders' expectations of 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 reliable and efficient electric service;
- Attracting and retaining an experienced and effective management team;
- Motivating and rewarding our management team to produce growth and performance for our shareholders that are 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 2010 executive compensation program are:

- As the chart below indicates, the Company delivered total shareholder return for 2010 and annualized total shareholder return for the three-years ending December 31, 2010 that were between the median of the total shareholder returns of the Company's Benchmarking and PSSP Peer Group as defined on pages 27 and 34, respectively.

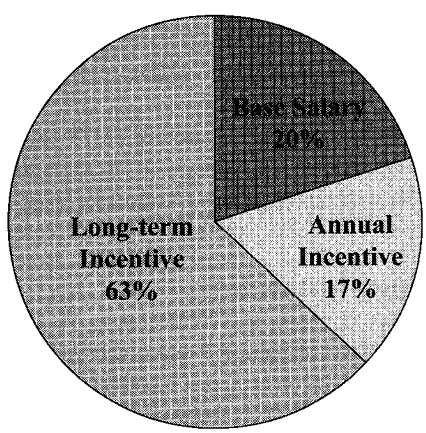
Relative Total Shareholder Return:
Progress Energy vs. Median of Benchmarking and PSSP Peer Groups



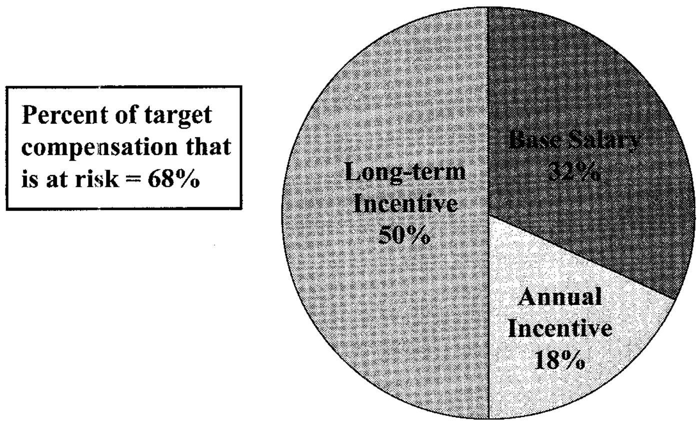
- Our chief executive officer's (CEO) total compensation, as shown in the "Summary Compensation Table" on page 47 of this Proxy Statement is largely flat since 2008 (+0.6%) (the first full year he was in the position) and decreased 3.5% from the amount of total compensation he received in 2009.
- Met our commitment to our customers to provide safe, reliable and competitively priced electric service.
- The Company reported ongoing earnings for 2010 of $889 million, or $3.06 per share, compared to $846 million, or $3.03 per share in 2009.
- Our named executive officers' (NEOs) target (i.e., opportunity) total compensation levels were approximately 25% below the 50th percentile of our benchmarking peer group as defined below in the Competitive Benchmarking section on page 27.
- We continue to provide only minimal executive perquisites (only those prevalent in the marketplace and that are conducive to promoting our desired business outcomes). No tax gross-ups were made on any perquisites.
- All of our NEOs currently meet or exceed the Company's market competitive executive stock ownership guidelines (as shown below in the table on page 28).
- Payments under the Management Incentive Compensation Plan ("MICP") and the Performance Share Sub-Plan ("PSSP") are based on the achievement of multiple performance factors that we believe drive shareholder value.
- We continue to strongly believe in a pay-for-performance culture. The charts below illustrate the percentage of performance-based compensation for our CEO and our NEOs.

CEO Mix of Target Compensation

Percent of target compensation that is at risk = 80%



NEO (Excluding CEO) Mix of Target Compensation



- The Organization and Compensation Committee of the Company's Board of Directors (in this Compensation Discussion and Analysis section, the "Committee") made a number of its decisions in consideration of the challenging economic environment such as:
    - no increases to the CEO's and other NEOs' base salaries other than one market-based adjustment, and
    - a 20% reduction in the annual grant of restricted stock units (RSUs).
- The Company will adopt a compensation recoupment policy that will, at a minimum, comply with the final rules issued under the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"). Pursuant to the Dodd-Frank Act, in the event the Company is required to prepare an accounting restatement due to material non-compliance with financial reporting requirements under the U.S. securities laws, the Company would be required to recover compensation regardless of whether the executive officers covered by the recoupment policy engaged in misconduct or otherwise caused or contributed to the requirement for restatement.
- Our CEO has agreed 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 proposed merger with Duke Energy Corporation, he will not receive a tax gross-up for any of his excise tax obligation (as disclosed below on page 38).

For 2010, the Company's NEOs were:

- William D. Johnson, Chairman, President and Chief Executive Officer;
- Mark F. Mulhern, Senior Vice President and Chief Financial Officer;
- Jeffrey J. Lyash, Executive Vice President – Energy Supply (formerly Executive Vice President – Corporate Development);
- Lloyd M. Yates, President and Chief Executive Officer, Progress Energy Carolinas, Inc. (PEC); and
- John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary.

I. COMPENSATION OVERVIEW

ASSESSMENT OF RISK

Our Company is highly regulated at both the federal and state levels; therefore, significant swings in earnings performance or growth over time are less influenced by any particular individual or groups of individuals. 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 CEO and approximately 50% 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 relative total shareholder return targets.
- The MICP focuses on ongoing earnings per share and legal entity net income, because we believe that these are the best measures to assess the change in the intrinsic value of the Company over time and therefore to determine how successful the Company is in its fundamental business.
- The executive officers receive restricted stock units that generally have a three-year vesting period so that their upside potential and downside risk are aligned with that of our shareholders and promote long-term performance over the vesting period.
- The executive officers are subject to stock ownership guidelines independently set by the Committee to align with our shareholders' interests over the long-term.
- The Committee has discretion to adjust all incentive awards based on factors it deems appropriate, including the Company'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 is administered by the Committee, which is composed of seven independent directors (as defined under the NYSE Corporate Governance Rules). Members of the Committee do not receive compensation under any compensation program in which our executive officers participate. For a discussion of director compensation, see the "Director Compensation" section on page 71 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 regularly meets with its consultant in executive session to discuss matters independent of management. Under the terms of its engagement, in 2010 Meridian reported directly to the Committee. Meridian solely provides executive compensation advisory services to the Committee and provides no other services to the Committee or the Company.

Our executive officers and other members of management periodically meet with the compensation consultant to ensure the consultant understands the Company's business strategy. Our executive officers and other Company employees provide the consultant with information regarding our executive compensation and benefit plans and how we administer them on an as-needed basis. In addition, the executive officers ensure that the Committee receives administrative support and assistance, and make recommendations to the Committee to ensure that compensation plans are aligned with our business strategy and meet the principles described above. John R. McArthur, our Executive Vice President, serves as management's liaison to the Committee. William D. Johnson, our 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 the 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 believes its compensation philosophy is 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, the Chief Executive Officer's target incentive opportunity is 85% 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 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 restricted shares 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 since 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 targets and/or grant date values for our compensation programs appear.

Target total compensation opportunities are intended to approximate the 50th percentile of our 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 assess overall compensation, the Committee utilizes tally sheets that provide a summary of the elements of compensation for each senior executive. The tally sheets indicate target and actual pay earned. They also summarize potential retirement benefits at age 65, current equity holdings and potential value from severance.

The compensation opportunities vary significantly from individual to individual based on the specific nature of the executive position. For example, our CEO is responsible for the overall performance of the Company 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 CEO'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 peers. For 2010, the Committee approved the use of a peer group of 18 integrated utilities used in the prior year and added three new companies: CenterPoint Energy, Inc., CMS Energy Corporation, and NiSource, Inc. (the "Benchmarking Peer Group"). These companies were added to further the Benchmarking Peer Group's alignment with the executive market in which the Company competes for talent. Further, the addition of the new peer companies positioned the Company's revenue more closely to the overall median than the previous peer group. The Benchmarking Peer Group is comprised of utilities that have transmission, distribution and generation assets and was chosen based primarily on revenues. The median revenue of the Benchmarking Peer Group is $10.3 billion compared to the Company'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.	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.

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. This means Progress Energy and its peer companies are primarily rate-of-return regulated, operate in the full range of the value chain (generation, transmission and/or delivery), and typically have requirements to serve all customers under state utility regulations. 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 Company received shareholder approval of the Progress Energy 2009 Executive Incentive Plan (the "EIP"), an annual cash incentive plan for the Company's named executive officers, at its 2009 Annual Meeting of Shareholders. 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 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 the Company's long-term success. The guidelines require each senior executive to own a multiple of his or her base salary in the form of Company 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.

The Committee benchmarked both the position levels and the multiples in our guidelines against those of the Benchmarking Peer Group and general industry practices. The benchmarking for 2010 indicated that the Company's guidelines were "at market" with respect to ownership levels, the types of equity that count toward ownership, and the timeframe for compliance. The Committee also considered the results of the vote on a shareholder proposal included in the Company's 2010 Proxy Statement that proposed the Committee adopt a policy requiring senior executives to retain no less than 75% of net after-tax shares acquired through equity compensation programs until the year following termination of employment through retirement or otherwise. The Committee did not adopt such a policy in 2010 based in part on the fact that approximately 76% of the votes cast were against the proposal. The stock ownership guidelines for our executive officer positions are shown in the table below:

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.

As of February 25, 2011, our named executive officers exceeded the guidelines (see Management Ownership table on page 11 of this Proxy Statement for specific details). As an indication of Mr. Johnson's alignment of his interests with that of our shareholders, he currently holds equity valued at more than 12 times his base salary (based on the closing share price on February 25, 2011), which exceeds the 5-times base salary required under the guidelines.

II. ELEMENTS OF COMPENSATION

The table below summarizes the current elements of our 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 necessary to attract and retain.	Short-term (annual)
Annual Incentive	Variable compensation based on achievement of annual performance goals.	Rewards operating performance results that are consistent with 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 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 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 and retaining executives.	Long-term
Management Change-In-Control Plan	Defines 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) retaining executives during transition following a change-in-control; and (iii) focusing executives on maximizing value for shareholders.	Long-term
Employment Agreements	Define Company's relationship with its executives and provide protection to each of the parties in the event of termination of employment.	Aid in attracting and retaining executives.	Long-term
Executive Perquisites	Personal benefits awarded outside of base pay and incentives.	Aid in attracting 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 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 and retaining executives.	Long-term

The table below shows the target awards of short-term and long-term incentives to each NEO for 2010. Percentages for incentives are expressed as a percentage of base salary. Additional elements of compensation are discussed further in this section.

Incentive Targets					
		Short-Term (annual)	Long-Term Incentive Targets as a Percentage of Salary		Total
Named Executive Officer	Base Salary (as of 1/1/11)	Incentive Target[1]	Performance Shares[2]	Restricted Stock	Incentive Target
William D. Johnson	$990,000	85%	233%	117%	435%
Mark F. Mulhern	$450,000	55%	117%	58%	230%
Jeffrey J. Lyash	$453,000	55%	117%	58%	230%
Lloyd M. Yates	$448,000	55%	117%	58%	230%
John R. McArthur	$488,000	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 identified on page 27 and 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). 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, the Chief Executive Officer then recommends to the Committee base salary adjustments for our executive officers (excluding himself). The Committee reviews the proposed base salaries, 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, and approves them in the first quarter of each year. The Committee meets in executive session with the compensation consultant to review and establish the Chief Executive Officer's base salary.

2. ANNUAL INCENTIVE

We sponsor the MICP, 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 the CEO, the threshold, target and outstanding levels for the performance measures applicable to the named executive officers. The 2010 MICP performance measures were ongoing earnings per share (Ongoing EPS) and legal entity net income for PEC and PEF as shown in the table below:

2010 MICP Financial Performance Goals			
(in millions except EPS)	**Threshold**	**Target**	**Outstanding**
Company Ongoing EPS	$2.75	$2.95	$3.05
PEC Net Income	$572	$605	$623
PEF Net Income	$405	$429	$441

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. Effective January 1, 2010, the legal entity net income performance measure was implemented as a result of the Company's desire to increase its legal entity focus on 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 the Company's performance. During the year, updates are provided to the Committee on the Company's performance as compared to the performance measures. For 2010, the named executive officers' 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**	**Company Ongoing EPS**	**PEC Net Income**	**PEF Net Income**
William D. Johnson	85%	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 named executive officer 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, we calculate 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 named executive officers.

Second, the CEO recommends to the Committee an MICP payment for executives (excluding the CEO) based on the executive's target award opportunity, the degree to which the Company achieved certain goals, and the executive's individual performance based on achieving individual goals and operating results. The Committee reviews the CEO's recommendations and approves and/or makes adjustments as appropriate. The CEO's MICP payment is determined by the Committee based upon the Committee's annual evaluation of the CEO's 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 the Company in its annual earnings release.

Based on management's recommendations, with respect to 2010, the Committee exercised discretion for the three performance measures: the Company's Ongoing EPS, PEC net income and PEF net income. The Committee approved adjusting the Company's earnings per share results downward by $0.22 to account for favorable weather, storm and regulatory costs. The Committee approved adjusting PEC net income for favorable weather, storm and regulatory costs for a net downward adjustment of $32 million. The Committee approved adjusting PEF net income downward by $42 million to account for favorable weather and regulatory costs. These adjustments resulted in the Company's Ongoing EPS, PEC net income and PEF net income performance at 73%, 74% and 82% of target, respectively. As a result of these downward adjustments, the 2010 MICP payments were below the target award opportunity for each of the NEOs.

3. LONG-TERM INCENTIVES

The 2007 Equity Incentive Plan (the "Equity Incentive Plan") was approved by our shareholders in 2007 and allows the Committee to make various types of long-term incentive awards to Equity Incentive Plan participants, including the named executive officers. The awards are provided to the named executive officers to align the interests of each executive with those of the Company's shareholders. Long-term incentive awards are intended to offer target award opportunities that approximate the 50th percentile of the peer group. Currently, the Committee utilizes two types of equity-based incentives: restricted stock units and performance shares.

The Committee has determined that to accomplish our compensation program's purposes effectively, equity-based awards should consist of one-third restricted stock units 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 the Company'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 restricted stock units to vest.

The table below shows the 2010 long-term incentive targets for the NEOs' positions.

Long-Term Incentive Award Target[1]		
Position[2]	**Performance Shares Target Award 2010**	**Restricted Stock Units Target Award 2010[3]**
Chief Executive Officer	233%	117%
Executive Vice President	117%	58%
Chief Financial Officer	117%	58%
President, PEC	117%	58%

[1] Target award amounts are expressed as percentages of base salaries for the listed positions.

[2] Position held at Progress Energy, Inc. unless otherwise noted.

[3] NEOs' 2010 RSU target award amounts were reduced by 20%.

After October 2004, we ceased granting stock options. All previously granted stock options remain valid in accordance with their terms and conditions.

Performance Shares

The Performance Share Sub-Plan 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 the Company's common stock, and earned performance share awards are paid in Company 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 shares granted at the beginning of each performance cycle, the Company 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 2010, the Committee did not exercise this discretion with respect to any grant of the named executive officers.

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 the Company was undergoing transformation of its underlying operating portfolio, this measure was intended to filter out external or market-based variations in the Company's stock price and focus on internal restructuring. The performance measure also uses the Company's publicly reported ongoing earnings 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 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
2007 Total Business Return[1]	5%	8%	≥10.5%
2007 Percentage of Target Award Earned	50%	100%	200%
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 the Company's ongoing earnings per share 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 2010, the Committee approved a payout of 125% of the target value for the 2007 – 2009 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 absolute earnings growth, the 2009 PSSP allows the Committee to consider the Company'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 the Company'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. The table below shows the percent of target awards that may be earned based on the Company'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 the Company'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 companies with a business strategy similar to ours 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	Great Plains Energy, Inc.	SCANA Corporation
American Electric Power, Inc.	NV Energy, Inc.	Southern Company
Consolidated Edison, Inc.	PG&E Corporation	Westar Energy, Inc.
DPL, Inc.	Pinnacle West Capital Corporation	Wisconsin Energy Corp.
Duke Energy Corporation	Portland General Electric Company	Xcel Energy, Inc.

Earnings Growth

Earnings growth is based on the Company's annual Ongoing EPS. Ongoing EPS is determined in accordance with the Company's "Policy for Press Release Earnings Disclosure of Non-GAAP Measures." The earnings growth component of the PSSP award is based on the Company'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 2010 annual grant were appropriate in consideration of a challenging economy, consistency with analysts' expectations, the 2010 projected analysts' consensus on earnings growth for the PSSP Peer Group, and continued uncertainties of the Florida regulatory environment. The table below shows the percent of target awards that may be earned based on the Company'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	
Threshold	2%	1%	50%
Target	4%	3%	100%
Maximum	6%	5%	200%

Restricted Stock Units

The restricted stock unit component of the current long-term incentive program helps us retain executives and aligns the interests of management with those of our 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.

Executive officers typically receive a grant of service-based RSUs in the first quarter of each year which are subject to a three-year graded vesting schedule. The size of each grant is based on the executive officer's target award percentage and is determined by using the closing price of the Company'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 26 above. The 2010 RSU targets for the NEOs are shown in the "Long-Term Incentive Award Target" table on page 32 above. The granting of RSUs does not provide the participant with any guarantee of vesting in the awards. Holders of RSUs receive quarterly cash dividend equivalents equal to the amount of any quarterly dividends paid on our common stock.

To further accent the retention quality of the Equity Incentive Plan and to recognize the contribution of the officer team, including the named executive officers, the Committee may also issue in its discretion service-based ad hoc grants of restricted stock units to executives. No ad hoc grants were awarded by the Committee during 2010.

4. SUPPLEMENTAL SENIOR EXECUTIVE RETIREMENT PLAN

The Supplemental Senior Executive Retirement Plan ("SERP") 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, 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 named executive officers 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 the Company'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 named executive officers to ensure that the named executive officers 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 named executive officer's 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 named executive officers participate in the SERP and are fully vested in the SERP other than John R. McArthur, who will begin participation and vest on January 1, 2012.

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, the target benefit percentage is 2.25% rather than 4% per year of service. None of the named executive officers for 2010 is subject to the new benefit percentage.) Benefits under the SERP are fully offset by Social Security benefits and by benefits paid under our 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.

5. MANAGEMENT CHANGE-IN-CONTROL PLAN

We sponsor 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 the Company. Providing such protection to executive officers in general minimizes disruption during a pending or anticipated CIC. Under our CIC Plan, we generally define 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 then outstanding securities; or
- the date a tender offer for the ownership of more than 50% of our then outstanding voting securities is consummated; or
- the date we consummate a merger, share exchange or consolidation with any other corporation or entity, regardless of whether we are the surviving company, unless our 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 the Board of Directors; or
- the date when our 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 our Board of Directors determines should constitute a CIC.

The purposes of the CIC Plan and the levels of payment it provides are designed to:

- 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 shareholders and customers.

The Committee has the sole authority and discretion to designate employees and/or positions for participation in the CIC Plan. 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 the Company 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 the Company'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 Company. 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).
Stock Option Agreements	Unvested awards if assumed by acquiring company would vest according to their normal schedule; otherwise they would vest if participant is terminated during coverage period after the CIC (there are no unvested stock option awards currently outstanding).
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.

In the event an NEO is terminated following a change-in-control of the Company, benefits payable under the CIC Plan will be paid in lieu of any severance benefits payable under the NEO's employment agreement if the transaction qualifies as a change in control under Section 409A of the Internal Revenue Code of 1986, as amended. If the transaction is not a Section 409A change in control, the NEO will receive the same level of CIC Plan benefits except that a portion of the cash severance will be paid in installments rather than in a lump sum. Accordingly, the amounts shown in the "Involuntary or Good Reason Termination (CIC)" columns in the tables captioned "Potential Payments Upon Termination," on pages 61 through 70 below show only the potential payments each of our NEOs would be eligible to receive under the CIC Plan in the event of a CIC.

The CIC Plan also permits the Board to establish a nonqualified trust to protect the benefits of the impacted participants. This type of trust generally is established 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 will be irrevocable and inaccessible to future or current management, and may be currently funded. To date, no such trust has been funded with respect to any of our NEOs.

Application of the CIC Plan and Other Compensation Related Consequences of the Proposed Merger with Duke Energy

On January 8, 2011, Duke Energy Corporation ("Duke Energy") and the Company entered into an Agreement and Plan of Merger (the "Merger Agreement"). Pursuant to the Merger Agreement, if the merger is consummated, the Company will become a wholly owned subsidiary of Duke Energy and shareholders of the Company will receive shares of Duke Energy common stock. Consummation of the merger is subject to customary conditions, including among other things, approval of the shareholders of each company.

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 61 through 70 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, Diamond Acquisition Corporation 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 the Company 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 their employment agreements, 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 Company common stock and outstanding awards of restricted stock, restricted stock units, 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 Company 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 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 the CIC Plan must be amended prior to the consummation of the merger to eliminate any funding requirement.

On March 16, 2011, the Board amended the SERP in two respects. The SERP was amended to provide that all service with the Company 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.

6. EMPLOYMENT AGREEMENTS

Each named executive officer has an employment agreement that documents the Company'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 a named executive officer 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 named executive officer's 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 52 of this Proxy Statement.

The Committee provides employment agreements to the named executive officers because it believes that such agreements are important for the Company to be competitive and retain a cohesive management team. The employment agreements also provide for a defined employment arrangement with the executives and provide various protections for the Company, such as prohibiting competition with the Company, solicitation of the Company's employees and disclosure of confidential information or trade secrets. The Committee believes that the terms of the employment agreements are in line with general industry practice.

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 47.

The Committee has determined that the current perquisites are appropriate and consistent with market practices. The perquisites available to the named executive officers during 2010 include:

Perquisites for 2010	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 the Company's aircraft in the event of a family emergency or similar situation is permitted with the approval of the Chief Executive Officer. Executives' spouses may travel on the Company's aircraft to accompany the executives to "business-related" events executives' spouses are requested to attend. For 2010, the named executive officers 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 named executive officer's total compensation.

8. OTHER BROAD-BASED BENEFITS

The named executive officers receive our general corporate benefits provided to all of our regular, full-time, nonbargaining employees. These broad-based benefits include the following:

- participation in our 401(k) Plan (including a limited Company match of up to 6% of eligible compensation);
- participation in our 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

We sponsor the Management Deferred Compensation Plan (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 401(k) plan.

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 Company's 401(k) Plan. Effective September 1, 2010, the named executive officers cannot allocate deferred awards to the deemed Company stock investment fund.

III. 2010 COMPENSATION DECISIONS

Company Performance

The Committee made decisions for the executive officers' compensation following the provisions of the compensation plans and benefit programs described in Article II, Elements of Compensation. The Committee also considered a number of factors in exercising its permitted discretion under the plans, including the challenging economic environment, the performance of the Company's nuclear fleet, and the Company's overall operational and financial results. Highlights of the Company's 2010 performance include the following:

- Returned value to shareholders including increasing dividends from $693 million in 2009 to $717 million in 2010; maintained the dividend rate in the face of a challenging economic environment;
- Total shareholder return in 2010 was 12.6% as compared to the median 2010 total shareholder return for the PSSP Peer Group of 14.9%; the Company's three-year annualized total shareholder return was 2.6% as compared to the median three-year annualized total shareholder return for the PSSP Peer Group of 4.1%;
- Delivered ongoing earnings of $889 million, or $3.06 per share, compared to $846 million, or $3.03 per share in 2009;
- PEC ongoing net income was $618 million and PEF ongoing net income was $462 million for 2010;
- Experienced higher operations and maintenance expense primarily due to higher nuclear plant outage and maintenance costs driven by expanded scope and more emergent work in 2010 as compared to 2009;
- Received approval from the Florida Public Service Commission to recover all proposed costs in Progress Energy Florida's annual filings for fuel and purchased power, environmental projects, conservation programs and new nuclear generation, including approval to collect, subject to refund, replacement power costs related to the Crystal River 3 Nuclear Plant outage;
- Received approval from the North Carolina Utilities Commission to recover all proposed costs of fuel, energy-efficiency programs and renewable energy resource; and
- Completed successful refueling and maintenance outage at Harris Nuclear Plant, executing several major projects, including an electric generator replacement, cooling tower fill project, and a fire protection enhancement.

Chief Executive Officer Compensation

William D. Johnson

In March 2010, the Committee considered Mr. Johnson's salary against the salaries of the chief executive officers in the Benchmarking Peer Group, the Company's performance, the difficult external economic climate and the performance of our nuclear fleet. Based on these factors, the Committee did not approve an increase to Mr. Johnson's salary of $990,000. Mr. Johnson's current target total base compensation is approximately 9% below the 50th percentile of the Benchmarking Peer Group due to his relatively short tenure in the Chief Executive Officer position, and more significantly, the challenging economic environment. It is the Committee's intention to increase Mr. Johnson's salary over time to a level that is at the 50th percentile of the Benchmarking Peer Group. For 2010, the Committee set Mr. Johnson's MICP target award opportunity at 85% of base salary. This target award was the same as the target Mr. Johnson had in 2007 after he assumed his new position, and represents a target award opportunity that is below the 50th percentile of market. The payout of the 2010 MICP award was based on the extent to which Mr. Johnson achieved his performance goals, which were focused on the following general areas of Company success:

- Delivering on fundamentals of safety, operational excellence and customer satisfaction;
- Strengthening nuclear performance through a fleet alignment initiative;
- Achieving financial objectives and strengthening financial accountability and understanding throughout the Company;
- Managing capital projects and programs effectively;
- Executing the energy-efficiency and emerging technology features of the Company's Balanced Solution Strategy;
- Fostering a more constructive regulatory environment in Florida;
- Advocating effectively for achievable, affordable climate and renewable energy policies;
- Achieving sustainable internal efficiency improvements through the application of the Company's Continuous Business Excellence ("CBE") initiative; and
- Demonstrating leadership behaviors that fully engage employees in executing our strategy and that foster a positive culture of people, performance and excellence.

In recognition of his accomplishments during 2010, the Committee awarded Mr. Johnson an MICP payout of $715,000, which is equal to 85% of Mr. Johnson's target award. The Committee considered, among other things, Mr. Johnson's leadership in achieving ongoing EPS of $3.06 which was higher than the upper end of the Company's guidance range of $3.00 to $3.05; managing 21 major capital projects that collectively came in 6% under budget for the year-end; increasing renewable energy capacity; successfully applying CBE resulting in all business units, except nuclear, holding operations and maintenance ("O&M") expenses flat at 2009 levels; and guiding the strategic direction of the Company that resulted in the execution of the Merger Agreement with Duke Energy. The Committee also considered the Company's challenges in the nuclear business unit, including higher than budgeted utility non-fuel O&M related to unplanned nuclear outages at the Robinson Nuclear Plant. The Committee recognized Mr. Johnson's focus on improving nuclear fleet performance by strengthening the leadership of the entire generating fleet and developing a comprehensive nuclear fleet renewal plan. The Committee also considered Mr. Johnson's emphasis on specific leadership behaviors and expectations throughout the year, which were communicated to the Company's management team in clear and direct terms. The Committee also noted Mr. Johnson's increasing leadership in key national industry organizations, including frequent, direct engagement with policymakers and regulators at the federal and state levels.

With respect to his long-term incentive compensation during 2010, Mr. Johnson was granted 22,596 restricted stock units and 56,248 performance shares in accordance with his pre-established targets of 117% and 233%, respectively, of his base salary. The performance shares are earned based on performance over the three years ending December 31, 2012. Additionally, 29,456 shares of the 2007 annual grant vested in 2010 and were paid out at 125% of target. The total year-over-year compensation to Mr. Johnson for 2010, as compared to 2009, as noted in the "Summary Compensation Table" on page 47 of this Proxy Statement, was largely flat.

Chief Financial Officer Compensation

Mark F. Mulhern

In March 2010, Mr. Johnson recommended the Committee approve a market-based adjustment to Mr. Mulhern's base salary. The Committee approved a base salary of $450,000 for Mr. Mulhern, representing a 5.9% increase to his previous salary of $425,000. The new base salary was set at 15.9% below the 50th percentile of the Benchmarking Peer Group. Mr. Mulhern's base salary was established at this level due to his relatively short tenure in the Chief Financial Officer position, and more significantly, the challenging economic environment. 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 2010, 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 2010 focused on the following general areas of Company success:

- Achieving financial objectives;
- Successfully communicating to the financial market modifications of financial goals that reflect changes resulting from PEF regulatory outcomes;
- Focusing on capital discipline and O&M expense management; and
- Providing financial support for and ensuring strategic alignment of the Company's Balanced Solution Strategy.

In recognition of his accomplishments in 2010 and on Mr. Johnson's recommendation, the Committee awarded Mr. Mulhern an MICP payout of $205,000, which is equal to 84% of Mr. Mulhern's target award. The Committee considered, among other things, Mr. Mulhern's significant role in the Company achieving a 12.6% shareholder return as of the end of the year; implementation of an integrated strategic planning process including appropriate focus on capital discipline, O&M expense management, and long-term workforce planning; supporting a successful rate settlement for PEF requiring adaptation of the Company's financial plan to absorb no new cash revenue during the settlement period; and negotiating and executing the Merger Agreement with Duke Energy. The Committee also noted Mr. Mulhern's leadership in coordinating the development of the financial components for the Company's regulatory strategy and strategic scenario planning.

With respect to his long-term incentive compensation, in 2010, Mr. Mulhern was granted 4,809 restricted stock units and 12,126 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, 2012. Additionally, 7,131 shares of the 2007 annual grant vested in 2010 and were paid out at 125% of target. Mr. Mulhern's compensation in 2010, as noted in the "Summary Compensation Table" on page 47 of this Proxy Statement, increased by 8.2% from the amount of total compensation he received in 2009, largely due to an increase in his accrued pension benefits.

Compensation of Other Named Executive Officers

For 2010, Mr. Johnson recommended and the Committee approved no increases to the base salaries for Messrs. Lyash, Yates, and McArthur.

On Mr. Johnson's recommendation, the Committee awarded Messrs. Lyash, Yates, and McArthur 2010 MICP awards as described in the table below.

Named Executive Officer	2010 MICP Award	Percent of Target	Explanation of Award
Jeffrey J. Lyash	$195,000	78%	Mr. Lyash played a significant role in developing and implementing a comprehensive nuclear fleet renewal plan; accelerating the CBE initiative into nuclear outages; improving performance of the Brunswick Nuclear Plant; and maintaining regulatory confidence in the Company's nuclear generation group's leadership.
Lloyd M. Yates	$195,000	79%	Mr. Yates played a significant role in achieving the successful financial and operational performance of PEC which contributed to the Company achieving its ongoing EPS goal; effectively managing PEC's O&M expenses, particularly for nuclear outages and in the supply chain business unit; and effectively communicating the Company's climate change policy and Balanced Solution Strategy to external stakeholders and industrial customers.
John R. McArthur	$220,000	82%	Mr. McArthur played a significant role in developing a North Carolina legislative approach for 2011 to support consistent regulated earnings and cost recovery for nuclear investment; improving our business planning process through better alignment and deeper understanding of our business objectives and cost drivers; achieving success in all clause recovery dockets in Florida; recovering all fuel and efficiency and renewable costs and incentives in North Carolina and South Carolina; and negotiating and executing the Merger Agreement with Duke Energy.

With respect to long-term compensation, in 2010 each of the other named executive officers received annual grants of restricted stock units 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 2011, 2012 and 2013	Performance Shares Vesting 2013
Jeffrey J. Lyash	5,126	12,924
Lloyd M. Yates	5,069	12,782
John R. McArthur	5,522	13,923

Mr. Lyash's total compensation as shown in the "Summary Compensation Table" on page 47 of this Proxy Statement decreased 10.6% from the amount of total compensation he received in 2009.

Mr. Yates' total compensation as shown in the "Summary Compensation Table" on page 47 of this Proxy Statement decreased 3.2% from the amount of total compensation he received in 2009.

Mr. McArthur's total compensation as shown in the "Summary Compensation Table" on page 47 of this Proxy Statement decreased 3.3% from the amount of total compensation he received in 2009.

IV. COMPENSATION COMMITTEE REPORT

The Committee has reviewed and discussed this CD&A with management as required by Item 402(b) 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 FOR 2010

The following Summary Compensation Table discloses the compensation during 2010 of our Chief Executive Officer, Chief Financial Officer, and the other three most highly paid executive officers who were serving at the end of 2010. 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] ($) (c)	Bonus ($) (d)	Stock Awards[2] ($) (e)	Option Awards[3] ($) (f)	Non-Equity Incentive Plan Compensation[4] ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings[5] ($) (h)	All Other Compensation[6] ($) (i)	Total ($) (j)
William D. Johnson,	2010	$990,000	N/A	$3,109,607	—	$715,000	$1,096,829	$316,051	$6,227,487
Chairman, President and	2009	979,231		3,090,605	—	950,000	1,144,448	289,726	6,454,010
Chief Executive Officer[7]	2008	950,000		2,911,701	—	929,000	1,091,256	304,571	6,186,528
Mark F. Mulhern,	2010	$443,269	N/A	$667,916	—	$205,000	$517,696	$77,672	$1,911,553
Senior Vice President and	2009	414,231		655,990	—	225,000	369,822	102,137	1,767,180
Chief Financial Officer	2008	355,385		433,473	—	200,000	820,419	141,354	1,950,631
Jeffrey J. Lyash,	2010	$453,000	N/A	$711,892	—	$195,000	$281,882	$102,290	$1,744,064
Executive Vice President –	2009	450,846		728,120	—	235,000	244,369	292,061	1,950,396
Energy Supply	2008	432,885		612,952	—	225,000	323,904	140,812	1,735,553
Lloyd M. Yates, President	2010	$448,000	N/A	$704,043	—	$195,000	$342,925	$80,548	$1,770,516
and Chief Executive	2009	445,846		720,683	—	235,000	308,815	119,432	1,829,776
Officer, PEC	2008	429,231		612,952	—	210,000	777,983	155,042	2,185,208
John R. McArthur,	2010	$488,000	N/A	$766,911	—	$220,000	$81,601	$92,677	$1,649,189
Executive Vice President,	2009	485,846		780,070	—	250,000	74,001	116,381	1,706,298
General Counsel and	2008	459,423		571,390	—	250,000	46,028	137,536	1,464,377
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 Management Deferred Compensation Plan. 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. Assumptions made in the valuation of material stock awards are discussed in Note 9.B. to our consolidated financial statements for the year ended December 31, 2010. The values reflected for 2008 in columns (e) and (j) are different than originally disclosed because these values represent the fair value of stock awards as of the grant date rather than the expense related to equity awards for financial statement reporting purposes in accordance with ASC Topic 718. Fair value of stock awards granted in 2010 and the maximum potential payout for the performance shares granted in 2010 are based on the March 16, 2010 closing stock price of $39.44 as shown in the table below:

	2010 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	$891,186	$2,218,421	$3,109,607	200%	$4,436,842
Mark F. Mulhern	189,667	478,249	667,916	200%	956,498
Jeffrey J. Lyash	202,169	509,723	711,892	200%	1,019,446
Lloyd M. Yates	199,921	504,122	704,043	200%	1,008,244
John R. McArthur	217,788	549,123	766,911	200%	1,098,246

[3] We ceased granting stock options in 2004. No additional expense remains with respect to our stock option program.

[4] Includes the awards given under the Management Incentive Compensation Plan (MICP) for 2008, 2009 and 2010 performance.

[5] Includes the change in present value of the accrued benefit under Progress Energy's Pension Plan, SERP, and/or 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
2010	5.50%	5.70%	5.00%
2009	5.95%	6.10%	5.45%
2008	6.30%	6.30%	6.25%

In addition, it 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 Management Deferred Compensation Plan, which does not have a guaranteed rate of return. Named executive officers 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 named executive officers are shown in the table below:

2010 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	$80,055	$1,005,387	—	$11,387	$1,096,829
Mark F. Mulhern	57,308	460,388	—	—	517,696
Jeffrey J. Lyash	60,279	221,603	—	—	281,882
Lloyd M. Yates	41,092	301,833	—	—	342,925
John R. McArthur	41,256	—	40,345	—	81,601

[6] Includes the following items: Company match contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; deferred credits under Management Deferred Compensation Plan (MDCP); perquisites; the Company'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 dividends paid under provisions of the Restricted Stock Award/Unit Plans. The total value of perquisites and personal benefits received by Messrs. Mulhern and Yates was less than $10,000 each. Thus, those amounts are excluded from this column. Named executive officers were compensated for these items as follows:

2010 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	$44,700	$65,145	$6,201	$185,305	$316,051
Mark F. Mulhern	14,700	11,601	—	5,521	45,850	77,672
Jeffrey J. Lyash	14,700	12,480	24,012	315	50,784	102,291
Lloyd M. Yates	14,700	12,180	—	3,125	50,543	80,548
John R. McArthur	13,569	14,580	11,058	722	52,748	92,677

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 health club dues, spousal meals, spousal travel, Internet and telecom access, AD&D insurance, residential telephone, meals (family other than spouse), and registration fee (family other than spouse).

2010 Perquisites (Component of column (i))						
Name	**Luncheon Club Dues**	**Financial/Tax Planning**	**Home Security**	**Spousal Travel on Corporate Aircraft***	**Other**	**Total Perquisites**
William D. Johnson	$1,508	$7,500	$30,128	$20,228	$5,781	$65,145
Jeffrey J. Lyash	2,088	6,583	918	11,934	2,489	24,012
John R. McArthur	1,476	7,500	840	0	1,242	11,058

* Executives' spouses may travel on the Company's aircraft only to accompany executives on "business-related" events that spouses are requested to attend.

[7] Mr. Johnson did not receive additional compensation for his service on the Board of Directors.

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, President and Chief Executive Officer	MICP 3/4/11	$420,750	$841,500	$1,683,000					
	Restricted Stock Units 3/16/10							22,596	$891,186
	PSSP 3/16/10				28,124	56,248	112,496		$2,218,421
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	MICP 3/4/11	$121,899	$243,798	$487,596					
	Restricted Stock Units 3/16/10							4,809	$189,667
	PSSP 3/16/10				6,063	12,126	24,252		$478,249
Jeffrey J. Lyash, Executive Vice President – Energy Supply	MICP 3/4/11	$124,575	$249,150	$498,300					
	Restricted Stock Units 3/16/10							5,126	$202,169
	PSSP 3/16/10				6,462	12,924	25,848		$509,723
Lloyd M. Yates, President and Chief Executive Officer, PEC	MICP 3/4/11	$123,200	$246,400	$492,800					
	Restricted Stock Units 3/16/10							5,069	$199,921
	PSSP 3/16/10				6,391	12,782	25,564		$504,122
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	MICP 3/4/11	$134,200	$268,400	$536,800					
	Restricted Stock Units 3/16/10							5,522	$217,788
	PSSP 3/16/10				6,962	13,923	27,846		$549,123

[1] The Management Incentive Compensation Plan is considered a non-equity incentive compensation plan. Award amounts are shown at threshold, target, and maximum levels. The target award is calculated using the 2010 eligible earnings times the executive's target percentage. See target percentage in table on page 31 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 2010 PSSP grants. The grant size was calculated by multiplying the executive's salary as of January 1, 2010, times his 2010 PSSP target and dividing by the December 31, 2009, closing stock price of $41.01. The Threshold column reflects the minimum payment level under our PSSP, which is 50% of the target amount shown in the Target column. The amount shown in the maximum column is 200% of the target amount.

[3] Reflects the number of restricted stock units granted during 2010 under the 2007 Equity Incentive Plan. The number of shares granted was determined by multiplying the executive's salary as of January 1, 2010, times his 2010 restricted stock target and dividing by the December 31, 2009, closing stock price of $41.01.

[4] Reflects the grant date fair value of the award based on the following assumptions: Market value of restricted stock granted on March 16, 2010, based on closing price of $39.44 per share, times the shares granted in column (i). Market value of PSSP granted on March 16, 2010, based on closing stock price on March 16, 2010, of $39.44 times target number of shares in column (g). The 2010 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 the Company 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. We may elect not to extend an executive officer's agreement and must notify the officer of such an election at least 60 days prior to the automatic extension date. 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 Senior Management Committee 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.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards[1]					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable (b)	Number of Securities Underlying Unexercised Options (#) Unexercisable (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)[2]	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)[3]	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)[4]	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[4]
William D. Johnson, Chairman, President and Chief Executive Officer	—	—	—	—	—	72,248	$3,141,343	112,869	$4,907,526
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	7,000	—	—	$44.75	9/30/2013	15,725	$683,723	20,733	$901,486
Jeffrey J. Lyash, Executive Vice President – Energy Supply	—	—	—	—	—	17,559	$763,465	24,941	$1,084,416
Lloyd M. Yates, President and Chief Executive Officer, PEC	—	—	—	—	—	17,454	$758,900	24,792	$1,077,968
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	—	—	—	—	—	18,299	$795,641	25,178	$1,094,716

[1] All outstanding stock options were vested as of December 31, 2006. The Company ceased granting stock options in 2004.

[2] Consists of outstanding restricted stock grants and restricted stock units as follows:

Number of Shares or 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	March 14, 2011	5,534	1,167	1,367	1,367	1,667
Restricted Stock Units	March 16, 2011	7,532	1,603	1,708	1,689	1,840
Restricted Stock Units	March 17, 2011	9,297	1,868	2,159	2,135	2,329
Restricted Stock Units	March 18, 2011	7,651	1,136	1,597	1,597	1,497
Restricted Stock Units	March 20, 2011	4,936	1,189	1,576	1,576	1,477
Restricted Stock Units	March 16, 2012	7,532	1,603	1,709	1,690	1,841
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	7,532	1,603	1,709	1,690	1,841
Total (column (g))		**72,248**	**15,725**	**17,559**	**17,454**	**18,299**

[3] Market value of shares or units of stock that have not vested is based on a December 31, 2010, closing price of $43.48 per share.

[4] The 2008 grant vests on January 1, 2011; the 2009 grant vests on January 1, 2012; and the 2010 grant vests on January 1, 2013. Performance share value for the 2009 annual grant is expected to be at 0% of target while the 2008 annual grant and 2010 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, 2010 closing stock price ($43.48). 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 named executive officers 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, 2011	54,125	8,069	11,443	11,443	10,637
Performance Shares	January 1, 2012	0	0	0	0	0
Performance Shares	January 1, 2013	58,744	12,664	13,498	13,349	14,541
Total (column (i))		**112,869**	**20,733**	**24,941**	**24,792**	**25,178**

OPTION EXERCISES AND STOCK VESTED

Name (a)	Option Awards: Number of Shares Acquired on Exercise (#) (b)	Option Awards: Value Realized on Exercise ($) (c)	Stock Awards: Number of Shares Acquired on Vesting (#) (d)[1]	Stock Awards: Value Realized on Vesting ($) (e)[2]
William D. Johnson, Chairman, President and Chief Executive Officer	—	—	76,448	$3,080,112
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	—	—	26,504	$1,064,791
Jeffrey J. Lyash, Executive Vice President – Energy Supply	—	—	31,031	$1,248,972
Lloyd M. Yates, President and Chief Executive Officer, PEC	—	—	31,006	$1,247,986
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	—	—	30,632	$1,231,050

[1] Reflects the number of restricted stock shares, restricted stock units, and performance shares that vested in 2010 for named executive officers as shown in the table below.

Number of Shares Acquired on Vesting (column (d))							
Stock Award	Vesting Date	Vesting Price	William D. Johnson	Mark F. Mulhern	Jeffrey J. Lyash	Lloyd M. Yates	John R. McArthur
Performance Shares	January 1, 2010	$41.01	43,965	10,644	14,232	14,232	13,229
Restricted Stock	March 14, 2010	$38.60	5,533	1,167	1,367	1,367	1,667
Restricted Stock	March 15, 2010	$38.60	5,067	—	1,100	1,100	1,434
Restricted Stock	March 21, 2010	$39.45	—	3,500	—	—	—
Restricted Stock Units	March 17, 2010	$39.44	9,297	1,868	2,159	2,134	2,328
Restricted Stock Units	March 18, 2010	$39.82	7,650	1,136	1,597	1,597	1,497
Restricted Stock Units	March 22, 2010	$39.84	4,936	8,189	10,576	10,576	10,477
Total (column (d))			**76,448**	**26,504**	**31,031**	**31,006**	**30,632**

[2] The value realized is the sum of the vested shares for each vesting date times the vesting price. Values realized on vesting during 2010 for named executive officers are shown in the table below:

Value Realized on Vesting (column (e))							
Stock Award	Vesting Date	Vesting Price	William D. Johnson	Mark F. Mulhern	Jeffrey J. Lyash	Lloyd M. Yates	John R. McArthur
Performance Shares	January 1, 2010	$41.01	$1,803,005	$436,510	$583,654	$583,654	$542,521
Restricted Stock	March 14, 2010	$38.60	$213,574	$45,046	$52,766	$52,766	$64,346
Restricted Stock	March 15, 2010	$38.60	$195,586	—	$42,460	$42,460	$55,352
Restricted Stock	March 21, 2010	$39.45	—	$138,075	—	—	—
Restricted Stock Units	March 17, 2010	$39.44	$366,674	$73,674	$85,151	$84,165	$91,816
Restricted Stock Units	March 18, 2010	$39.82	$304,623	$45,236	$63,593	$63,593	$59,611
Restricted Stock Units	March 22, 2010	$39.84	$196,650	$326,250	$421,348	$421,348	$417,404
Total (column (e))			**$3,080,112**	**$1,064,791**	**$1,248,972**	**$1,247,986**	**$1,231,050**

PENSION BENEFITS TABLE

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, President and Chief Executive Officer	Progress Energy Pension Plan	18.3	$528,633	$0
	Supplemental Senior Executive Retirement Plan	25.3[2]	$8,287,871[3]	$0
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	Progress Energy Pension Plan	14.8	$326,707	$0
	Supplemental Senior Executive Retirement Plan	14.8	$1,605,155[4]	$0
Jeffrey J. Lyash, Executive Vice President – Energy Supply	Progress Energy Pension Plan	17.6	$334,696	$0
	Supplemental Senior Executive Retirement Plan	17.6	$1,640,811[5]	$0
Lloyd M. Yates, President and Chief Executive Officer, PEC	Progress Energy Pension Plan	12.1	$198,700	$0
	Supplemental Senior Executive Retirement Plan	12.1	$1,367,539[6]	$0
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	Progress Energy Pension Plan	9.1	$192,479	$0
	Restoration Retirement Plan	9.1	$162,615	$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, 2010, for computation of accumulated benefit under the Supplemental Senior Executive Retirement Plan and the Progress Energy Pension Plan were 5.70% and 5.50% respectively. Additional details on the formulas for computing benefits under the Supplemental Senior Executive Retirement Plan 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 $1,046,261.

[4] Based on an estimated annual benefit payable at age 65 of $282,595.

[5] Based on estimated annual benefit payable at age 65 of $322,742.

[6] Based on estimated annual benefit payable at age 65 of $254,485.

NONQUALIFIED DEFERRED COMPENSATION

The table below shows the nonqualified deferred compensation for each of the named executive officers. Information regarding details of the deferred compensation plans currently in effect can be found under the heading "Deferred Compensation" in the CD&A on page 41 of this Proxy Statement. In addition, the Deferred Compensation Plan for Key Management Employees is discussed in footnote 5 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, President and Chief Executive Officer	$0	$44,700	$68,932[5]	$0	$849,703
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	$22,163	$11,601	$20,715	($147,094)[6]	$233,261
Jeffrey J. Lyash, Executive Vice President – Energy Supply	$0	$12,480	$20,359	$0	$168,012
Lloyd M. Yates, President and Chief Executive Officer, PEC	$22,400	$12,180	$66,737	$0	$601,121
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	$73,200	$14,580	$29,600	$0	$301,215

[1] Reflects salary deferred under the Management Deferred Compensation Plan, which is reported as "Salary" in the Summary Compensation Table. For 2010, named executive officers deferred the following percentages of their base salary: (i) Mulhern – 5%; Yates – 5%; and McArthur – 15%.

[2] Reflects registrant contributions under the Management Deferred Compensation Plan, 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: Management Incentive Compensation Plan, Management Deferred Compensation Plan, Performance Share Sub-Plan, and Deferred Compensation Plan for Key Management Employees.

[4] Includes December 31, 2010 balances under the following deferred compensation plans: Management Incentive Compensation Plan, Performance Share Sub-Plan, Management Deferred Compensation Plan, and Deferred Compensation Plan for Key Management Employees. Balances for named executive offices under each deferral plan are shown in the table below:

Aggregate Balance at Last FYE (column (f))					
Name	**Management Deferred Compensation Plan**	**Management Incentive Compensation Plan**	**Deferred Compensation for Key Management Employees**	**Performance Share Sub-Plan**	**Total (column (f))**
William D. Johnson	$492,740	$77,712	$279,251	—	$849,703
Mark F. Mulhern	$116,631	$77,537	—	$39,093	$233,261
Jeffrey J. Lyash	$168,012	—	—	—	$168,012
Lloyd M. Yates	$190,251	$121,356	—	$289,514	$601,121
John R. McArthur	$301,215	—	—	—	$301,215

[5] Includes above market earnings of $11,387 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.

[6] Mr. Mulhern received distributions from his Management Incentive Deferred Compensation Plan: $84,465; Management Deferred Compensation Plan: $0; and Performance Share Sub-Plan: $62,629.

CASH COMPENSATION AND VALUE OF VESTING EQUITY TABLE

The following table shows the actual cash compensation and value of vesting equity received in 2010 by the named executive officers. The Committee believes that this table is important in order to distinguish between the actual cash and vested value received by each named executive officer 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 2010) (b)[2]	Deferred Compensation under MDCP and MICP (c)[3]	Restricted Stock / Units Vesting (d)[4]	Performance Shares Vesting (e)[5]	Restricted Stock / Unit Dividends (f)[6]	Stock Options Vesting (g)[7]	Perquisite (h)[8]	Tax Gross-ups (i)[9]	Total
William D. Johnson, Chairman, President and Chief Executive Officer	$990,000	$950,000	$0	$1,277,107	$1,803,005	$185,305	$0	$65,145	$6,201	$5,276,763
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	$443,269	$225,000	$22,163	$628,280	$436,510	$45,850	$0	$8,408	$5,521	$1,792,838
Jeffrey J. Lyash, Executive Vice President – Energy Supply	$453,000	$235,000	$0	$665,318	$583,654	$50,784	$0	$24,012	$315	$2,012,083
Lloyd M. Yates, President and Chief Executive Officer, PEC	$448,000	$235,000	$22,400	$664,332	$583,654	$50,543	$0	$9,874	$3,125	$1,994,528
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary	$488,000	$250,000	$73,200	$688,529	$542,521	$52,748	$0	$11,058	$722	$2,033,578

[1] Consists of the total 2010 base salary earnings prior to (i) employee contributions to the Progress Energy 401(k) Savings & Stock Ownership Plan and (ii) voluntary deferrals, if applicable, under the Management Deferred Compensation Plan (MDCP) shown in column (c).

[2] Awards given under the Management Incentive Compensation Plan (MICP) attributable to Plan Year 2009 and paid in 2010.

[3] Consists of amounts deferred under the MDCP and the MICP. These deferral amounts are part of Base Pay and/or Annual Incentive and therefore are not included in the Total column.

[4] Reflects the value of restricted stock and restricted stock units vesting in 2010. 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 restricted stock units was calculated using the closing stock price for Progress Energy Common Stock on the business day prior to when vesting occurred.

[5] Reflects the value of performance shares vesting on January 1, 2010. The value of the 2007 performance share units were calculated using the closing stock price for Progress Energy Common Stock on the business day prior to when distribution occurred.

[6] Reflects dividends and dividend equivalents paid as the result of outstanding restricted stock or restricted stock units held in Company Plan accounts.

[7] Reflects the value of any stock options vesting in 2010. Since we ceased granting stock options under our Incentive Plans in 2004, all outstanding options had fully vested by 2006.

[8] Reflects the value of all perquisites provided during 2010. For a complete listing of the perquisites, see the "Executive Perquisites" section of the "Elements of Compensation" discussion of the CD&A on page 40 of this Proxy Statement. Perquisite details for each named executive officer are discussed in the Summary Compensation Table footnotes.

[9] Reflects the Company'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 2010.

POTENTIAL PAYMENTS UPON TERMINATION
William D. Johnson, Chairman, President and Chief Executive Officer

	Voluntary Termination ($)	Early Retirement[1] ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC)[12] ($)	Disability ($)	Death ($)
Compensation							
Base Salary—$990,000[2]	$0	$0	$2,960,100	$0	$5,712,500	$594,000	$0
Annual Incentive[3]	$0	$715,000	$0	$0	$841,500	$715,000	$715,000
Long-term Incentives:							
Performance Shares (PSSP)[4]							
2008 PSSP Grant	$0	$2,353,332	$0	$0	$2,353,332	$2,353,332	$2,353,332
2009 PSSP Grant	$0	$0	$0	$0	$2,692,674	$0	$1,795,116
2010 PSSP Grant	$0	$851,398	$0	$0	$2,554,194	$851,398	$851,398
Restricted Stock Units[5]							
2007 RSU Grant	$0	$362,188	$0	$0	$429,235	$429,235	$429,235
2008 RSU Grant	$0	$304,925	$0	$0	$332,665	$332,665	$332,665
2009 RSU Grant	$0	$792,466	$0	$0	$1,156,351	$1,156,351	$1,156,351
2010 RSU Grant	$0	$450,322	$0	$0	$982,474	$0	$0
Restricted Stock[6]							
2006 RS Grant	$0	$240,618	$0	$0	$240,618	$240,618	$240,618
Benefits and Perquisites							
Incremental Nonqualified Pension[7]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[8]	$849,703	$849,703	$849,703	$849,703	$849,703	$849,703	$849,703
Post-retirement Health Care[9]	$0	$0	$24,682	$0	$48,396	$0	$0
Executive AD&D Proceeds[10]	$0	$0	$0	$0	$0	$500,000	$500,000
280G Tax Gross-up[11]	$0	$0	$0	$0	$5,488,512	$0	$0
TOTAL	**$849,703**	**$6,919,952**	**$3,834,485**	**$849,703**	**$23,682,154**	**$8,022,302**	**$9,223,418**

[1] Mr. Johnson became eligible for early retirement at age 55 in January 2009. Therefore, under the voluntary termination and involuntary not 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. 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 ($990,000) 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 average MICP award for the three years prior (($990,000 + $914,167) 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 85% times $990,000. 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, 2010, this is based on the full award. For 2010, Mr. Johnson's MICP award was $715,000.

[4] Amounts shown for performance shares are based on a December 31, 2010, closing price of $43.48 per share. Unvested performance shares would be forfeited under for cause termination. Voluntary termination and involuntary not for cause termination are not applicable. See footnote 1. 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 2008 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2009 and 2010 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 restricted stock units are based on a December 31, 2010, closing price of $43.48 per share. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Unvested units would be forfeited under for cause termination. Voluntary termination and involuntary not for cause termination are not applicable. See footnote 1. In the event of early retirement, Mr. Johnson would receive a pro-rata percentage of all unvested units, 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 restricted stock units would vest immediately. Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Johnson would immediately vest restricted stock units granted in 2007, 2008, and 2009, and would forfeit restricted stock units granted in 2010.

[6] Amounts shown for restricted stock shares are based on a December 31, 2010, closing price of $43.48 per share. For a detailed description of outstanding restricted stock shares, see "Outstanding Equity Awards at Fiscal Year-End Table." Unvested shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. In the event of early retirement, all outstanding shares may vest at the Committee's discretion. In the event of involuntary or good reason termination (CIC), all outstanding shares would vest immediately. Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Johnson's restricted stock grant dates are beyond the one-year threshold; therefore, all outstanding restricted stock shares would vest immediately.

[7] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Johnson was vested under the SERP as of December 31, 2010, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC). For a detailed description of the accumulated SERP benefit and estimated annual benefit payable at age 65, see "Pension Benefits Table." In the event of early retirement, Mr. Johnson would receive a 2.5% decrease in his accrued SERP benefit for each year that he is younger than age 65.

[8] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under voluntary termination, early retirement, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Unvested MICP deferral premiums would be forfeited. Mr. Johnson would forfeit $0 of unvested deferred MICP premiums.

[9] 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 $1,371.22 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 Company-paid medical, dental and vision coverage in the same plan Mr. Johnson was participating in prior to termination for 36 months at $1,344.33 per month.

[10] Mr. Johnson would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[11] Upon a change in control, the Management Change-in-Control Plan provides for the Company 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 $10,222,095 of excess parachute payments above his base amount. Those excess parachute payments result in $2,044,419 of excise taxes, $3,365,647 of tax gross-ups, and $78,446 of employer Medicare tax related to the excise tax payment. As discussed above, in connection with the merger with Duke Energy, Duke Energy, Diamond Acquisition Corporation 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, if Mr. Johnson is involuntarily terminated without "cause" or resigns for "good reason" following, but prior to the second anniversary of, the consummation of the merger, no tax gross-up will be provided.

[12] See "Management Change-in-Control Plan – Application of the CIC Plan and Other Compensation Related Consequences of the Proposed Merger with Duke Energy" on pages 38 through 39 above for a discussion regarding "involuntary" or "good reason" termination following the merger with Duke Energy.

POTENTIAL PAYMENTS UPON TERMINATION
Mark F. Mulhern, Senior Vice President and Chief Financial Officer

	Voluntary Termination ($)	Early Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC)[11] ($)	Disability ($)	Death ($)
Compensation							
Base Salary—$450,000[1]	$0	$0	$1,345,500	$0	$1,395,000	$270,000	$0
Annual Incentive[2]	$0	$0	$0	$0	$247,500	$205,000	$205,000
Long-term Incentives:							
Performance Shares (PSSP)[3]							
2008 PSSP Grant	$0	$0	$0	$0	$350,850	$350,850	$350,850
2009 PSSP Grant	$0	$0	$0	$0	$547,978	$0	$365,319
2010 PSSP Grant	$0	$0	$0	$0	$550,636	$183,545	$183,545
Restricted Stock Units[4]							
2007 RSU Grant	$0	$0	$0	$0	$103,352	$103,352	$103,352
2008 RSU Grant	$0	$0	$0	$0	$49,393	$49,393	$49,393
2009 RSU Grant	$0	$0	$0	$0	$271,141	$271,141	$271,141
2010 RSU Grant	$0	$0	$0	$0	$209,095	$0	$0
Restricted Stock[5]							
2006 RS Grant	$0	$0	$0	$0	$50,741	$50,741	$50,741
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$233,262	$0	$233,262	$233,262	$233,262	$233,262	$233,262
Post-retirement Health Care[8]	$0	$0	$15,249	$0	$19,934	$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	$1,141,872	$0	$0
TOTAL	**$233,262**	**$0**	**$1,594,011**	**$233,262**	**$5,170,754**	**$2,217,284**	**$2,312,603**

[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 ($450,000) 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 two times the sum of annual salary plus annual target MICP award (($450,000 + $247,500) 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 $450,000. 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, 2010, this is based on the full award. For 2010, Mr. Mulhern's MICP award was $205,000.

[3] Amounts shown for performance shares are based on a December 31, 2010, closing price of $43.48 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 2008 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2009 and 2010 performance grants, the target value of the award would be paid based upon time in the plan.

[4] Amounts shown for restricted stock units are based on a December 31, 2010, closing price of $43.48 per share. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Unvested restricted stock units 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 restricted stock units would vest immediately. Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Mulhern would immediately vest restricted stock units granted in 2007, 2008, and 2009; and would forfeit restricted stock units granted in 2010.

[5] Amounts shown for restricted stock shares are based on a December 31, 2010, closing price of $43.48 per share. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Unvested restricted stock 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 restricted stock shares would vest immediately. Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Mulhern's restricted stock grant dates are beyond the one-year threshold; therefore, all outstanding restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Mulhern was vested under the SERP as of December 31, 2010, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[7] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under voluntary termination, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Mr. Mulhern is not eligible for early retirement or normal retirement. Unvested MICP deferral premiums would be forfeited. Mr. Mulhern would forfeit $0 of unvested deferred MICP premiums.

[8] 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 $847.18 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 Company-paid medical, dental and vision coverage in the same plan Mr. Mulhern was participating in prior to termination for 24 months at $830.57 per month.

[9] Mr. Mulhern 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 the Company 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 $2,126,683 of excess parachute payments above his base amount. Those excess parachute payments result in $425,337 of excise taxes, $700,215 of tax gross-ups, and $16,320 of employer Medicare tax related to the excise tax payment.

[11] See "Management Change-in-Control Plan – Application of the CIC Plan and Other Compensation Related Consequences of the Proposed Merger with Duke Energy" on pages 38 through 39 above for a discussion regarding "involuntary" or "good reason" termination following the merger with Duke Energy.

POTENTIAL PAYMENTS UPON TERMINATION
Jeffrey J. Lyash, Executive Vice President – Energy Supply

	Voluntary Termination ($)	Early Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC)[11] ($)	Disability ($)	Death ($)
Compensation							
Base Salary—$453,000[1]	$0	$0	$1,354,470	$0	$2,106,450	$271,800	$0
Annual Incentive[2]	$0	$0	$0	$0	$249,150	$195,000	$195,000
Long-term Incentives:							
Performance Shares (PSSP)[3]							
2008 PSSP Grant	$0	$0	$0	$0	$497,544	$497,544	$497,544
2009 PSSP Grant	$0	$0	$0	$0	$633,345	$0	$422,230
2010 PSSP Grant	$0	$0	$0	$0	$586,872	$195,624	$195,624
Restricted Stock Units[4]							
2007 RSU Grant	$0	$0	$0	$0	$137,005	$137,005	$137,005
2008 RSU Grant	$0	$0	$0	$0	$69,438	$69,438	$69,438
2009 RSU Grant	$0	$0	$0	$0	$274,707	$274,707	$274,707
2010 RSU Grant	$0	$0	$0	$0	$222,878	$0	$0
Restricted Stock[5]							
2006 RS Grant	$0	$0	$0	$0	$59,437	$59,437	$59,437
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$168,012	$0	$168,012	$168,012	$168,012	$168,012	$168,012
Post-retirement Health Care[8]	$0	$0	$17,420	$0	$34,158	$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	$1,565,051	$0	$0
TOTAL	**$168,012**	**$0**	**$1,539,902**	**$168,012**	**$6,604,047**	**$2,368,567**	**$2,518,997**

[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 ($453,000) 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 annual target MICP award (($453,000 + $249,150) 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 $453,000. 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, 2010, this is based on the full award. For 2010, Mr. Lyash's MICP award was $195,000.

[3] Amounts shown for performance shares are based on a December 31, 2010, closing price of $43.48 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 2008 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2009 and 2010 performance grants, the target value of the award would be paid based upon time in the plan.

[4] Amounts shown for restricted stock units are based on a December 31, 2010, closing price of $43.48 per share. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Unvested restricted stock units 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 restricted stock units would vest immediately. Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Lyash would immediately vest restricted stock units granted in 2007, 2008, and 2009; and would forfeit restricted stock units granted in 2010.

[5] Amounts shown for restricted stock shares are based on a December 31, 2010, closing price of $43.48 per share. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Unvested restricted stock 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 restricted stock shares would vest immediately. Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Lyash's restricted stock grant dates are beyond the one-year threshold; therefore, all outstanding restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Lyash was vested under the SERP as of December 31, 2010, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[7] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under voluntary termination, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Mr. Lyash is not eligible for early retirement or normal retirement. Unvested MICP deferral premiums would be forfeited. Mr. Lyash would forfeit $0 of unvested deferred MICP premiums.

[8] 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 $967.80 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 Company-paid medical, dental and vision coverage in the same plan Mr. Lyash was participating in prior to termination for 36 months at $948.83 per month.

[9] Mr. Lyash 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 the Company 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 $2,914,834 of excess parachute payments above his base amount. Those excess parachute payments result in $582,967 of excise taxes, $959,715 of tax gross-ups, and $22,369 of employer Medicare tax related to the excise tax payment.

[11] See "Management Change-in-Control Plan – Application of the CIC Plan and Other Compensation Related Consequences of the Proposed Merger with Duke Energy" on pages 38 through 39 above for a discussion regarding "involuntary" or "good reason" termination following the merger with Duke Energy.

POTENTIAL PAYMENTS UPON TERMINATION
Lloyd M. Yates, President and Chief Executive Officer, PEC

	Voluntary Termination ($)	Early Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC)[11] ($)	Disability ($)	Death ($)
Compensation							
Base Salary—$448,000[1]	$0	$0	$1,339,520	$0	$2,083,200	$268,800	$0
Annual Incentive[2]	$0	$0	$0	$0	$246,400	$195,000	$195,000
Long-term Incentives:							
Performance Shares (PSSP)[3]							
2008 PSSP Grant	$0	$0	$0	$0	$497,544	$497,544	$497,544
2009 PSSP Grant	$0	$0	$0	$0	$626,219	$0	$417,479
2010 PSSP Grant	$0	$0	$0	$0	$580,424	$193,475	$193,475
Restricted Stock Units[4]							
2007 RSU Grant	$0	$0	$0	$0	$137,005	$137,005	$137,005
2008 RSU Grant	$0	$0	$0	$0	$69,438	$69,438	$69,438
2009 RSU Grant	$0	$0	$0	$0	$272,620	$272,620	$272,620
2010 RSU Grant	$0	$0	$0	$0	$220,400	$0	$0
Restricted Stock[5]							
2006 RS Grant	$0	$0	$0	$0	$59,437	$59,437	$59,437
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$601,121	$0	$601,121	$601,121	$601,121	$601,121	$601,121
Post-retirement Health Care[8]	$0	$0	$24,682	$0	$48,396	$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	$1,554,752	$0	$0
TOTAL	**$601,121**	**$0**	**$1,965,323**	**$601,121**	**$6,996,956**	**$2,794,440**	**$2,943,119**

[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 ($448,000) 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 annual target MICP award (($448,000 + $246,400) 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 $448,000. 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, 2010 this is based on the full award. For 2010, Mr. Yates' MICP award was $195,000.

[3] Amounts shown for performance shares are based on a December 31, 2010, closing price of $43.48 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 and the extent that the performance factors are satisfied. In the event of death, the 2008 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2009 and 2010 performance grants, the target value of the award would be paid based upon time in the plan.

[4] Amounts shown for restricted stock units are based on a December 31, 2010, closing price of $43.48 per share. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Unvested restricted stock units 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 restricted stock units would vest immediately. Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Yates would immediately vest restricted stock units granted in 2007, 2008, and 2009; and would forfeit restricted stock units granted in 2010.

[5] Amounts shown for restricted stock shares are based on a December 31, 2010, closing price of $43.48 per share. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Unvested restricted stock 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 restricted stock shares would vest immediately. Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Yates' restricted stock grant dates are beyond the one-year threshold; therefore, all outstanding restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Yates was vested under the SERP as of December 31, 2010, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[7] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under voluntary termination, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Mr. Yates is not eligible for early retirement or normal retirement. Unvested MICP deferral premiums would be forfeited. Mr. Yates would forfeit $0 of unvested deferred MICP premiums.

[8] 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 $1,371.22 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 Company-paid medical, dental and vision coverage in the same plan Mr. Yates was participating in prior to termination for 36 months at $1,344.33 per month.

[9] Mr. Yates 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 the Company 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 $2,895,652 of excess parachute payments above his base amount. Those excess parachute payments result in $579,130 of excise taxes, $953,400 of tax gross-ups, and $22,222 of employer Medicare tax related to the excise tax payment.

[11] See "Management Change-in-Control Plan – Application of the CIC Plan and Other Compensation Related Consequences of the Proposed Merger with Duke Energy" on pages 38 through 39 above for a discussion regarding "involuntary" or "good reason" termination following the merger with Duke Energy.

POTENTIAL PAYMENTS UPON TERMINATION
John R. McArthur, Executive Vice President, General Counsel and Corporate Secretary

	Voluntary Termination ($)	Early Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC)[11] ($)	Disability ($)	Death ($)
Compensation							
Base Salary—$488,000[1]	$0	$0	$1,459,120	$0	$2,269,200	$292,800	$0
Annual Incentive[2]	$0	$0	$0	$0	$268,400	$220,000	$220,000
Long-term Incentives:							
Performance Shares (PSSP)[3]							
2008 PSSP Grant	$0	$0	$0	$0	$462,480	$462,480	$462,480
2009 PSSP Grant	$0	$0	$0	$0	$683,179	$0	$455,453
2010 PSSP Grant	$0	$0	$0	$0	$632,237	$210,746	$210,746
Restricted Stock Units[4]							
2007 RSU Grant	$0	$0	$0	$0	$128,483	$128,483	$128,483
2008 RSU Grant	$0	$0	$0	$0	$65,090	$65,090	$65,090
2009 RSU Grant	$0	$0	$0	$0	$289,490	$289,490	$289,490
2010 RSU Grant	$0	$0	$0	$0	$240,097	$0	$0
Restricted Stock[5]							
2006 RS Grant	$0	$0	$0	$0	$72,481	$72,481	$72,481
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$1,483,339	$0	$0
Deferred Compensation[7]	$301,215	$0	$301,215	$301,215	$301,215	$301,215	$301,215
Post-retirement Health Care[8]	$0	$0	$16,626	$0	$32,599	$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	$2,347,525	$0	$0
TOTAL	**$301,215**	**$0**	**$1,776,961**	**$301,215**	**$9,275,815**	**$2,542,785**	**$2,705,438**

[1] There is no provision for payment of salary under voluntary termination, for cause termination or death. Mr. McArthur is not eligible for early retirement or normal retirement. 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 ($488,000) 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 annual target MICP award (($488,000 + $268,400) 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.

[2] 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 $488,000. 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, 2010, this is based on the full award. For 2010, Mr. McArthur's MICP award was $220,000.

[3] Amounts shown for performance shares are based on a December 31, 2010, closing price of $43.48 per share. Unvested performance shares would be forfeited 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), 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 performance measurement period and the extent that the performance factors are satisfied. In the event of death, the 2008 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2009 and 2010 performance grants, the target value of the award would be paid based upon time in the plan.

[4] Amounts shown for restricted stock units are based on a December 31, 2010, closing price of $43.48 per share. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Unvested restricted stock units would be forfeited 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), all outstanding restricted stock units would vest immediately. Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. McArthur would immediately vest restricted stock units granted in 2007, 2008, and 2009; and would forfeit restricted stock units granted in 2010.

[5] Amounts shown for restricted stock shares are based on a December 31, 2010, closing price of $43.48 per share. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Unvested restricted stock would be forfeited 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), all outstanding restricted stock shares would vest immediately. Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. McArthur's restricted stock grant dates are beyond the one-year threshold; therefore, all outstanding restricted stock shares would vest immediately.

[6] Mr. McArthur was not vested under the SERP as of December 31, 2010, 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 voluntary termination, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Mr. McArthur is not eligible for early retirement or normal retirement. Unvested MICP deferral premiums would be forfeited. Mr. McArthur would forfeit $0 of unvested deferred MICP premiums.

[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 $923.64 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 Company-paid medical, dental and vision coverage in the same plan Mr. McArthur was participating in prior to termination for 36 months at $905.53 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 the Company 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 $4,372,154 of excess parachute payments above his base amount. Those excess parachute payments result in $874,431 of excise taxes, $1,439,541 of tax gross-ups, and $33,553 of employer Medicare tax related to the excise tax payment.

[11] See "Management Change-in-Control Plan – Application of the CIC Plan and Other Compensation Related Consequences of the Proposed Merger with Duke Energy" on pages 38 through 39 above for a discussion regarding "involuntary" or "good reason" termination following the merger with Duke Energy.

DIRECTOR COMPENSATION

The following includes the required table and related narrative detailing the compensation each director received for his or her services in 2010.

Name (a)	Fees Earned or Paid in Cash[1] ($) (b)	Stock Awards[2] ($) (c)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (f)	All Other Compensation[3] ($) (g)	Total ($) (h)
John D. Baker II	$93,500	$60,000	—	—	—	$20,581	$174,081
James E. Bostic, Jr.	$93,500	$60,000	—	—	—	$112,696	$266,196
Harris E. DeLoach, Jr.	$103,500	$60,000	—	—	—	$89,058	$252,558
James B. Hyler, Jr.	$93,500	$60,000	—	—	—	$23,881	$177,381
Robert W. Jones	$103,500	$60,000	—	—	—	$66,607	$230,107
W. Steven Jones	$93,500	$60,000	—	—	—	$104,240	$257,740
Melquiades R. "Mel" Martinez	$78,188	$0	—	—	—	$2,424	$80,612
E. Marie McKee	$107,000	$60,000	—	—	—	$214,542	$381,542
John H. Mullin, III	$108,500	$60,000	—	—	—	$168,244	$336,744
Charles W. Pryor, Jr.	$93,500	$60,000	—	—	—	$35,787	$189,287
Carlos A. Saladrigas	$93,500	$60,000	—	—	—	$92,831	$246,331
Theresa M. Stone	$107,000	$60,000	—	—	—	$90,827	$257,827
Alfred C. Tollison, Jr.	$101,500	$60,000	—	—	—	$86,944	$248,444

[1] Reflects the annual retainer plus any Board or Committee fees earned in 2010. Amounts may have been paid in cash or deferred into the Non-Employee Director Deferred Compensation Plan.

[2] Reflects the grant date fair value of awards granted under the Non-Employee Director Stock Unit Plan in 2010. The assumptions made in the valuation of awards granted pursuant to the Non-Employee Director Stock Unit Plan are not addressed in our consolidated financial statements, footnotes to our consolidated financial statements or in Management's Discussion and Analysis because the Director Plan is immaterial to our consolidated financial statements. As a liability plan under FASB ASC Topic 718, the fair value of the Director Plan is re-measured at each financial statement date. The grant date fair value for each stock unit granted to each director on January 4, 2010 was $40.93. The numbers of stock units outstanding in the Non-Employee Director Stock Unit Plan as of December 31, 2010 for each Director listed above are shown in the table in footnote 3 below.

[3] Includes the following items: The dollar value of dividend reinvestments and unit appreciation/depreciation accrued under the Non-Employee Director Stock Unit Plan; and dividend reinvestments and unit appreciation/depreciation accrued under the Non-Employee Director Deferred Compensation Plan. The dollar values of dividend reinvestments and unit appreciation for each Director listed above are in the table below. The total value of the perquisites and personal benefits received by each director was less than $10,000. Thus, those amounts are excluded from this column. The numbers of stock units outstanding in the Non-Employee Director Deferred Compensation Plan as of December 31, 2010 for each Director listed above are in the table below.

	Non-Employee Director Stock Unit Plan		Non-Employee Director Deferred Compensation Plan		
Name	Stock Units Outstanding as of Dec. 31, 2010 (see footnote 2 above)	Dividend Reinvestments and Unit Appreciation/ Depreciation in column (g) ($) (see footnote 3 above)	Stock Units Outstanding as of Dec. 31, 2010 (see footnote 3 above)	Dividend Reinvestments and Unit Appreciation/ Depreciation in column (g) ($) (see footnote 3 above)	Total (column (g))
John D. Baker II	1,555	$7,619	3,153	$12,962	$20,581
James E. Bostic, Jr.	10,462	$50,586	13,104	$62,110	$112,696
Harris E. DeLoach, Jr.	6,255	$30,290	12,698	$58,768	$89,058
James B. Hyler, Jr.	3,227	$15,684	1,849	$8,197	$23,881
Robert W. Jones	4,739	$22,978	9,560	$43,629	$66,607
W. Steven Jones	7,856	$38,013	14,195	$66,227	$104,240
Melquiades R. "Mel" Martinez	0	$0	633	$2,424	$2,424
E. Marie McKee	13,449	$64,994	31,151	$149,548	$214,542
John H. Mullin, III	13,968	$67,498	21,034	$100,746	$168,244
Charles W. Pryor, Jr.	4,739	$22,978	2,805	$12,809	$35,787
Carlos A. Saladrigas	11,502	$55,603	7,867	$37,228	$92,831
Theresa M. Stone	7,856	$38,013	11,098	$52,814	$90,827
Alfred C. Tollison, Jr.	6,255	$30,290	12,250	$56,654	$86,944

DISCUSSION OF DIRECTOR COMPENSATION TABLE

RETAINER AND MEETING FEES

During 2010, Directors who were not employees of the Company received an annual retainer of $80,000, of which $30,000 was automatically deferred under the Non-Employee Director Deferred Compensation Plan (see below). The Lead Director/Chair of the following Board Committees received an additional retainer of $15,000: Audit and Corporate Performance Committee; Governance Committee; and Organization and Compensation Committee. The Chair of each of the following standing Board Committees received an additional retainer of $10,000: Finance Committee and Operations and Nuclear Oversight Committee. The nonchair members of the following standing Board Committees received an additional retainer of $7,500: Audit and Corporate Performance Committee and Organization and Compensation Committee. The nonchair members of the following standing Board Committees received an additional retainer of $6,000: Governance Committee; Finance Committee; and Operations and Nuclear Oversight Committee. In addition, a special meeting fee of $1,500 was paid to members of the Operations and Nuclear Oversight Committee in the January 1, 2011 retainer. The special meeting was held on September 15, 2010, and the special meeting fee was approved by the Governance Committee on December 7, 2010. The Nuclear Oversight Director received an additional retainer of $8,000. The Chair of the Nuclear Project Oversight Committee receives an attendance fee of $2,000 per meeting held by that Committee. Additionally, each member of the Nuclear Project Oversight Committee receives an attendance fee of $1,500 per meeting held by that Committee. Directors who are not employees of the Company received a fee of $1,500 per meeting, paid with the next quarterly retainer, for noncustomary meetings or reviews of the Company's operations that are approved by the Governance Committee. Directors who are employees of our Company do not receive an annual retainer or attendance fees. All Directors are reimbursed for expenses incidental to their service as Directors. Committee positions held by the Directors are discussed in the "Board Committees" section of this Proxy Statement.

Effective January 1, 2011, the cash component of the annual retainer was increased by $25,000. The annual retainer is now $105,000, of which $30,000 will be automatically deferred under the Non-Employee Director Deferred Compensation Plan (see below).

The Non-Employee Director Stock Unit Plan provides that each Director will receive an annual grant of stock units that is equivalent to $60,000.

NON-EMPLOYEE DIRECTOR DEFERRED COMPENSATION PLAN

In addition to $30,000 from the annual retainer that is automatically deferred, outside Directors may elect to defer any portion of the remainder of their annual retainer and Board attendance fees until after the termination of their service on the Board under the Non-Employee Director Deferred Compensation Plan. Any deferred fees are deemed to be invested in a number of units of Common Stock of the Company, but participating Directors receive no equity interest or voting rights in any shares of the Common Stock. The number of units credited to the account of a participating Director is equal to the dollar amount of the deferred fees divided by the average of the high and low selling prices (i.e., market value) of the Common Stock on the day the deferred fees would otherwise be payable to the participating Director. The number of units in each account is adjusted from time to time to reflect the payment of dividends on the number of shares of Common Stock represented by the units. Unless otherwise agreed to by the participant and the Board, when the participant ceases to be a member of the Board of Directors, he or she will receive cash equal to the market value of a share of the Company's Common Stock on the date of payment multiplied by the number of units credited to the participant's account.

NON-EMPLOYEE DIRECTOR STOCK UNIT PLAN

Effective January 1, 1998, we established the Non-Employee Director Stock Unit Plan ("Stock Unit Plan"). The Stock Unit Plan provides for an annual grant of stock units equivalent to $60,000 to each non-employee Director. Each unit is equal in economic value to one share of the Company's Common Stock, but does not represent an equity interest or entitle its holder to vote. The number of units is adjusted from time to time to reflect the payment of dividends with respect to the Common Stock of the Company. Effective January 1, 2007, a Director shall be fully vested at all times in the stock units credited to his or her account.

OTHER COMPENSATION

Directors are eligible to receive certain perquisites, including tickets to various cultural arts and sporting events, which are *de minimis* in value. Each retiring Director also receives a gift valued at approximately $1,500 in appreciation for his/her service on the Board.

We charge Directors with imputed income in connection with (i) their travel on Company aircraft for non-Company related purposes and (ii) their spouses' travel on Company aircraft.

EQUITY COMPENSATION PLAN INFORMATION
as of December 31, 2010

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	4,309,620	$44.08	5,570,969
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	4,309,620	$44.08	5,570,969

Column (a) includes stock options outstanding, outstanding performance units assuming maximum payout potential, and outstanding restricted stock units.

Column (b) includes only the weighted-average exercise price of outstanding options.

Column (c) includes reduction for unissued, outstanding performance units assuming maximum payout potential and unissued, outstanding restricted stock units, and issued restricted stock.

PROPOSAL 2—ADVISORY (NONBINDING) VOTE ON EXECUTIVE COMPENSATION

Section 951 of the Dodd-Frank Wall Street Reform and Consumer Protection Act ("the Dodd-Frank 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. On January 25, 2011, the SEC adopted final rules to implement the provisions of the Dodd-Frank Act that relate to shareholder approval of executive compensation arrangements. 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 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 the Board will take the outcome of the vote into account when considering future executive compensation arrangements.

The Company's executive compensation philosophy 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 2010 executive compensation program in connection with your vote on this proposal:

- The Company delivered total shareholder return for 2010 and annualized total shareholder return for the three-years ending December 31, 2010 that were between the median of the total shareholder returns of the Company's Benchmarking and Performance Share Sub-Plan Peer Group.
- Our Chief Executive Officer's total compensation is largely flat since 2008 (+0.6%) (the first full year he was in the position) and decreased 3.5% from the amount of total compensation he received in 2009.
- Met our commitment to our customers to prove safe, reliable and competitively priced electric service.
- The Company reported ongoing earnings for 2010 of $889 million, or $3.06 per share, compared to $846 million, or $3.03 per share, in 2009.
- Our NEOs' target (i.e., opportunity) total compensation levels were approximately 25% 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). No tax gross-ups were made on any perquisites.
- All of our NEOs currently meet or exceed the Company's market competitive executive stock ownership guidelines.

- 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.
- We continue to strongly believe in a pay-for-performance culture. In 2010, a significant portion of our NEOs' compensation (80% for the CEO and 68% for the other NEOs) was performance-based.
- The Compensation Committee made a number of its decisions in consideration of the challenging economic environment. Those decisions included no increases to the CEO's and the other NEOs' base salaries other than one market-based adjustment and a 20% reduction in the annual grant of Restricted Stock Units.
- The Company will adopt a compensation recoupment policy that will, at a minimum, comply with the final rules issued under the Dodd-Frank Act. Pursuant to the Dodd-Frank Act, in the event the Company is required to prepare an accounting restatement due to material non-compliance with financial reporting requirements under the U.S. securities laws, the Company would be required to recover compensation regardless of whether the executive officers covered by the recoupment policy engaged in misconduct or otherwise caused or contributed to the requirement for restatement.
- Our CEO has agreed 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 proposed merger with Duke Energy Corporation, he will not receive a tax gross-up for any of his excise tax obligation (as disclosed above on page 38).

See pages 29 to 45 of this Proxy Statement for more information regarding these elements of our executive compensation 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 DISCUSSION CONTAINED IN THIS PROXY STATEMENT.

PROPOSAL 3—ADVISORY (NONBINDING) VOTE ON THE FREQUENCY OF SHAREHOLDER VOTES ON EXECUTIVE COMPENSATION

In addition to the advisory vote on executive compensation, the Dodd-Frank Act and the SEC rules require companies to seek a nonbinding shareholder vote to advise whether the say-on-pay vote should occur every one, two or three years. Shareholders also have the option to abstain from voting on the matter.

The Board of Directors has determined that an annual advisory vote on executive compensation is the best approach for the Company. In making its determination, the Board was influenced by the fact that the compensation of our named executive officers ("NEOs") is evaluated, adjusted and approved on an annual basis. The Board believes that our shareholders' sentiment should be a factor that the Compensation Committee and the Board should consider as part of the annual compensation review and determination process. An annual advisory vote on executive compensation will enable our shareholders to provide us with direct input regarding our compensation philosophy, policies and practices as disclosed in the proxy statement every year.

You may cast your vote by choosing the option of one year, two years, three years, or abstain from voting in response to the resolution set forth below:

"RESOLVED, that the option of once every year, two years, or three years that receives the highest number of votes cast will be determined to be the preferred frequency with which the Company is to hold an advisory vote by shareholders to approve the compensation of our NEOs, as disclosed in the Compensation Discussion and Analysis section, the compensation tables and any related discussion contained in our annual meeting proxy statement."

The option of one year, two years or three years that receives the highest number of votes cast will be the frequency of the vote on the compensation of our NEOs that has been approved by our shareholders on an advisory basis. Although the vote is nonbinding, our Board of Directors will take the outcome of the vote into account when making future decisions about the Company's executive compensation policies and procedures.

THE BOARD OF DIRECTORS UNANIMOUSLY RECOMMENDS A VOTE, ON AN ADVISORY BASIS, FOR THE OPTION OF "1 YEAR" AS THE FREQUENCY WITH WHICH SHAREHOLDERS ARE PROVIDED AN ADVISORY VOTE ON EXECUTIVE COMPENSATION.

REPORT OF THE AUDIT AND CORPORATE PERFORMANCE COMMITTEE

The Audit and Corporate Performance Committee of the Company'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, 2010, 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 communication 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, 2010, for filing with the SEC.

Audit and Corporate Performance Committee

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 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 non-audit services provided by Deloitte. We have adopted policies and procedures for pre-approving all audit and permissible non-audit services rendered by Deloitte, and the fees billed for those services. Our Controller (the "Controller") is responsible to the Audit Committee for enforcement of this procedure, and for reporting noncompliance. Pursuant to the pre-approval policy, the Audit Committee specifically pre-approved the use of Deloitte for audit, audit-related and tax services.

The pre-approval policy requires management to obtain specific pre-approval from the Audit Committee for the use of Deloitte for any permissible non-audit 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 non-audit 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 non-audit 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 non-audit 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* non-audit services must be approved by the Audit Committee or its designated representative before the completion of the services. Non-audit 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 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 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, 2010 and 2009.

	2010	2009
Audit fees	$3,395,000	$3,581,000
Audit-related fees	64,000	91,000
Tax fees	22,000	19,000
Other fees	—	—
Total fees	$3,481,000	$3,691,000

Audit fees include fees billed for services rendered in connection with (i) the audits of our annual financial statements and those of our SEC reporting subsidiaries (Carolina Power & Light Company and Florida Power Corporation); (ii) the audit of the effectiveness of our internal control over financial reporting; (iii) the reviews of the financial statements included in our Quarterly Reports on Form 10-Q and those of our SEC reporting subsidiaries; (iv) accounting consultations arising as part of the audits; and (v) audit services in connection with statutory, regulatory or other filings, including comfort letters and consents in connection with SEC filings and financing transactions. Audit fees for 2010 and 2009 also include $1,175,000 and $1,265,000, respectively, for services in connection with the Sarbanes-Oxley Act Section 404 and the related PCAOB Standard No. 2 relating to our internal control over financial reporting.

Audit-related fees include fees billed for (i) special procedures and letter reports; (ii) benefit plan audits when fees are paid by us rather than directly by the plan; and (iii) accounting consultations for prospective transactions not arising directly from the audits.

Tax fees include fees billed for tax compliance matters and tax planning and advisory services.

The Audit Committee has concluded that the provision of the non-audit 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 4—RATIFICATION OF SELECTION OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Audit and Corporate Performance Committee of our 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, 2011, and has directed that management submit the selection of that independent registered public accounting firm for ratification by the shareholders at the 2011 Annual Meeting of the 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, 2011, requires approval by a majority of the votes actually cast by holders of Common Stock present in person or represented by proxy at the 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 Audit Committee and the Board of Directors recommend a vote "**FOR**" the ratification of the selection of Deloitte & Touche as our independent registered public accounting firm.

FINANCIAL STATEMENTS

Our 2010 Annual Report, which includes financial statements as of December 31, 2010 and 2009, and for each of the three years in the period ended December 31, 2010, together with the report of Deloitte & Touche LLP, our independent registered public accounting firm, was sent to those who were shareholders of record as of the close of business on March 4, 2011.

FUTURE SHAREHOLDER PROPOSALS

Shareholder proposals submitted for inclusion in the proxy statement for our 2012 Annual Meeting must be received no later than December 2, 2011, 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.

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 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.*

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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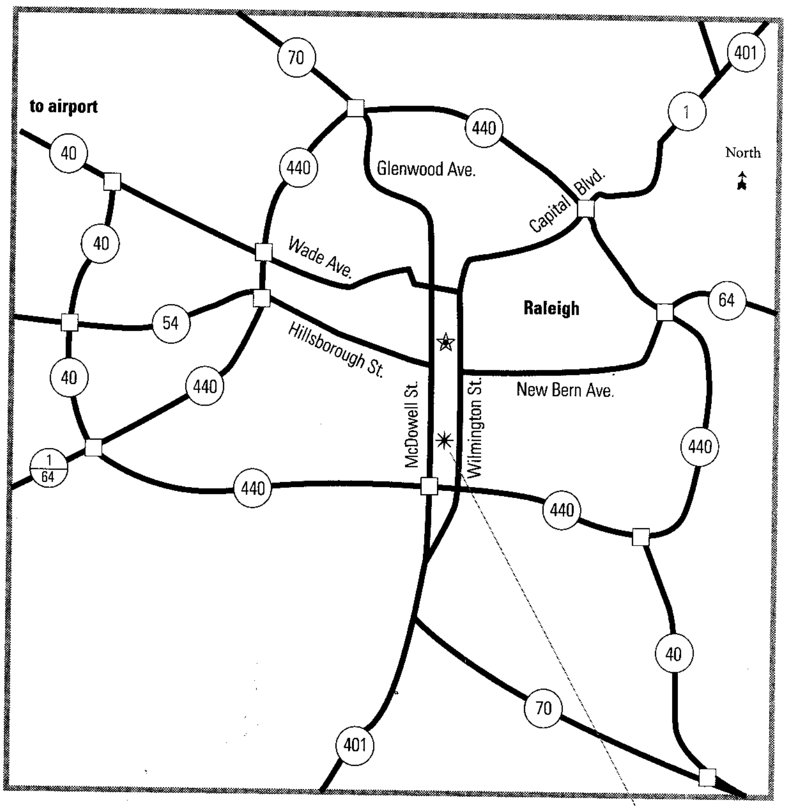
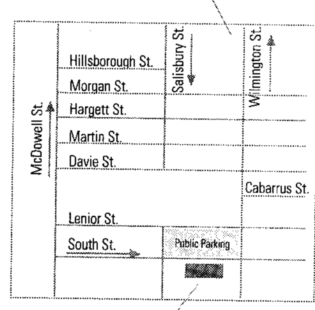
Directions to Progress Energy's 2011 Annual Shareholders' Meeting

Progress Energy Center for the Performing Arts
2 E. South Street, Raleigh, North Carolina





Progress Energy Center for the Performing Arts

BOARD OF DIRECTORS

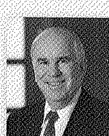
William D. Johnson
Chairman, President and Chief Executive Officer, Progress Energy, Inc. Raleigh, N.C.
Elected to the board in 2007. Serves as Chairman, Progress Energy Carolinas and Chairman, Progress Energy Florida.

John D. Baker II
Executive Chairman, Patriot Transportation Holding, Inc. (provides transportation services and real estate operations). Jacksonville, Fla.
Elected to the board in 2009 and sits on the following committees: Finance; Organization and Compensation.

James E. Bostic, Jr.
Managing Director, HEP & Associates (business consulting) and retired Executive Vice President, Georgia-Pacific Corp. (manufacturer and distributor of tissue, paper, packaging, building products, pulp and related chemicals). Atlanta, Ga.
Elected to the board in 2002 and sits on the following committees: Audit and Corporate Performance; Nuclear Project Oversight; Operations and Nuclear Oversight.

Harris E. DeLoach, Jr.
Chairman and Chief Executive Officer, Sonoco Products Co. (manufacturer of paperboard and paper and plastic packaging products). Hartsville, S.C.
Elected to the board in 2006 and sits on the following committees: Corporate Governance; Nuclear Project Oversight; Operations and Nuclear Oversight (Chair); Organization and Compensation.

James B. Hyler, Jr.
Retired Vice Chairman and Chief Operating Officer, First Citizens Bank. Raleigh, N.C.
Elected to the board in 2008 and sits on the following committees: Finance; Organization and Compensation.



Robert W. Jones
Sole owner, Turtle Rock Group, LLC (financial advisory consulting firm). Bedford, N.Y.
Elected to the board in 2007 and sits on the following committees: Corporate Governance; Finance (Chair); Organization and Compensation.

W. Steven Jones
Dean (Emeritus) and Professor of Strategy and Organizational Behavior at the Kenan-Flagler Business School at the University of North Carolina at Chapel Hill and formerly Chief Executive Officer of Suncorp-Metway Ltd. (banking and insurance in Australia). Chapel Hill, N.C.
Elected to the board in 2005 and sits on the following committees: Audit and Corporate Performance; Nuclear Project Oversight; Operations and Nuclear Oversight.

Melquiades R. "Mel" Martinez
Managing Director, JPMorgan Chase & Co. and former U.S. Senator from the state of Florida and former Secretary of the U.S. Department of Housing and Urban Development. Orlando, Fla.
Elected to the board in 2010 and sits on the following committees: Operations and Nuclear Oversight; Organization and Compensation.

E. Marie McKee
President, Corning Museum of Glass (world's most comprehensive collection of glass, spanning 3,500 years of glassmaking history) and retired Senior Vice President, Corning, Inc. Corning, N.Y.
Elected to the board in 1999 and sits on the following committees: Corporate Governance; Nuclear Project Oversight; Operations and Nuclear Oversight; Organization and Compensation (Chair).

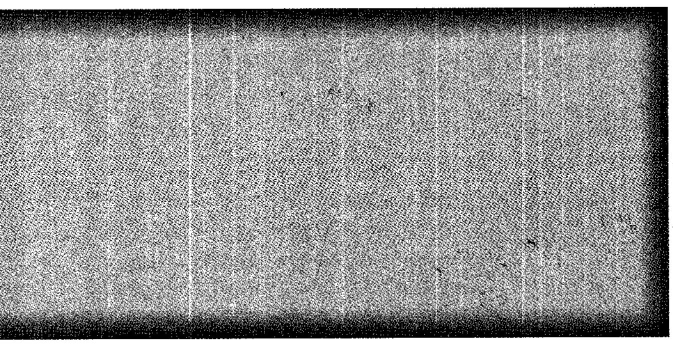
John H. Mullin, III
Chairman, Ridgeway Farm, LLC (farming and timber management) and formerly a Managing Director, Dillon, Read & Co. (investment bankers). Brookneal, Va.
Elected to the board in 1999, Lead Director, and sits on the following committees: Corporate Governance (Chair); Finance; Organization and Compensation.

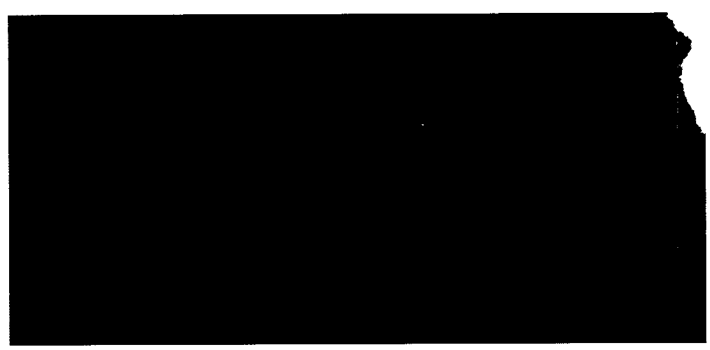
Charles W. Pryor, Jr.
Chairman, Urenco USA, Inc. (global provider of services and technology to the nuclear generation industry). Lynchburg, Va.
Elected to the board in 2007 and sits on the following committees: Audit and Corporate Performance; Nuclear Project Oversight (Chair); Operations and Nuclear Oversight.

Carlos A. Saladrigas
Chairman and Chief Executive Officer, Regis HRG (provides a full suite of outsourced human resources services to small and midsized businesses). Previously served as Chairman, Premier American Bank and retired Chief Executive Officer, ADP TotalSource. Miami, Fla.
Elected to the board in 2001 and sits on the following committees: Audit and Corporate Performance; Finance.

Theresa M. Stone
Executive Vice President and Treasurer, Massachusetts Institute of Technology and retired President, Lincoln Financial Media (financial services company). Boston, Mass.
Elected to the board in 2005 and sits on the following committees: Audit and Corporate Performance (Chair); Corporate Governance; Finance.

Alfred C. Tollison, Jr.
Retired Chairman and Chief Executive Officer, Institute of Nuclear Power Operations (a nuclear industry-sponsored nonprofit organization). Marietta, Ga.
Elected to the board in 2006 and sits on the following committees: Audit and Corporate Performance; Nuclear Project Oversight (Vice Chair); Operations and Nuclear Oversight.





Progress Energy

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