WE'RE LOOKING AT POWER IN A NEW LIGHT.

Progress Energy

2007 ANNUAL REPORT

We talk to customers every day so we know what they care about most. They want the lights to come on every time they flip the switch. They want real ways to save energy and money. Above all, they want to know we are working hard to ensure clean, reliable, affordable power. And every day, I have the satisfaction of assuring them that's exactly what we're doing.

— Kisha Camacho
Customer and Market Services
Progress Energy Florida

BRIGHT THINKING

FOR TODAY'S ENERGY LANDSCAPE.

At Progress Energy, we have one of the most powerful tools in the industry: the power of intelligent, innovative thinking. And we are focusing this powerful tool on our two regulated electric utilities, Progress Energy Carolinas and Progress Energy Florida. Our more than 10,000 employees are developing the best solutions for the energy challenges of today and tomorrow. We are implementing a Balanced Solution for meeting our growing area's energy needs, combining energy efficiency, alternative energy and state-of-the-art power generation. And we are working in partnership with our communities, building public and regulatory support. In short, we are developing a bright future for our company, customers and shareholders. And we're succeeding because every one of us is looking at power in a new light.

ENERGY EFFICIENCY
ALTERNATIVE ENERGY
STATE-OF-THE-ART PLANTS

TABLE OF CONTENTS

DEAR SHAREHOLDERS:

Our company produced strong results for customers and shareholders in 2007, and is adapting well to an industry landscape being shaped by climate change concerns and the growing demand for electricity. Focused on our two electric utilities, Progress Energy has a balanced strategy for long-term success. I'm optimistic about securing our energy future, in part because we're "looking at power in a new light."

I am pleased to report that in 2007 we increased our dividend for the 20th year in a row while delivering excellent service to our 3.1 million customers. We also once again met our core ongoing earnings-per-share target and further strengthened our balance sheet and credit quality. In late 2007, we announced the sale of the last of our non-utility subsidiaries, completing the transition back to our core business.

Sustaining this strategic focus and financial strength is critical as we prepare for the major construction projects ahead. For years to come, we will be investing heavily in the electric utility infrastructure necessary to keep up with population growth and new environmental and energy regulations.

People continue moving to the states where we provide retail electric service. Florida, North Carolina and South Carolina are all among the nation's top 10 in population growth, according to the U.S. Census Bureau. Our company's responsibility, as well as our business opportunity, is to be ready with the right mix of clean, reliable and cost-effective resources.

NEW REALITIES. In many ways, it's a new day in our industry. The single biggest issue is how best to meet the challenge of global climate change and population growth while ensuring reliable, affordable power for the future. This year, Progress Energy will issue an updated version of our 2006 report on climate change. We are working collaboratively with government leaders and others to develop consensus-based public policies to address this vital issue.

The new energy realities also include rising costs, emerging technologies and a groundswell of support for greater energy efficiency and alternative energy sources. Although challenges certainly remain, the prospects for building new state-of-the-art nuclear power plants are the best in many years.

It has become increasingly difficult to add new coal-fired generation without being able to capture and store the carbon emissions, and the nation must avoid over-reliance on natural gas as a fuel source because of its volatile price and uncertain supply. So, experts and policy-makers from a broad spectrum of interests now recognize that expanded

FINANCIAL HIGHLIGHTS

Years ended December 31 (in millions, except per share data)	2007	2006*	2005*
Financial Data			
Operating revenues	$9,153	$8,724	$7,948
Net income	504	571	697
Income from continuing operations	693	551	523
Core ongoing earnings per common share**	2.81	2.63	2.70
Reported GAAP earnings per common share	1.97	2.28	2.82
Average common shares outstanding	256	258	247
Common Stock Data			
Return on average common stock equity (percent)	5.97	7.05	8.91
Book value per common share	$32.66	$32.7[illegible]	$32.35
Market value per common share (closing)	$48.43	$49.08	$43.92

*Financial data has been restated for discontinued operations.

**See page 35 for a reconciliation of ongoing earnings per share to reported GAAP earnings per share.

20 YEARS OF DIVIDEND GROWTH

use of nuclear energy is an essential part of getting serious about addressing climate change.

SECURING THE FUTURE. To adapt to today's changing energy landscape, Progress Energy is implementing a balanced three-part strategy of aggressive energy efficiency, innovative alternative energy and state-of-the-art power plants. This annual report describes just a few examples of how we're moving forward on these three fronts.

Progress Energy Carolinas in 2007 doubled its energy-efficiency goal and announced an array of new efficiency initiatives, including a partnership to promote the use of compact fluorescent lights (CFLs). We solicited proposals for renewable energy projects and actively worked alongside diverse groups in the passage of new energy legislation in North Carolina and South Carolina. The North Carolina law established the first renewable energy standard in the Southeast.

Also in 2007, we announced a new natural gas-fired unit in Richmond County, N.C., and in early 2008 filed a federal license application for a potential new nuclear plant in Wake County, N.C. This keeps our option open on this project, but it is not yet a decision to build a new nuclear plant.

Meanwhile, Progress Energy Florida expanded its aggressive efficiency program, signed contracts for more renewable energy projects and launched a much-praised *SolarWise for Schools*℠ program. We also completed a new gas-fired unit at our Hines Energy Complex in Polk County, Fla.

In 2008 we plan to submit a federal license application and seek state approval for a potential new nuclear plant in Levy County, Fla. Given the growth in Florida, this nuclear project will likely be on a faster track than the one in North Carolina.

THE PEOPLE. My goal is to bring out the best in the people who work here so together we can bring out the best in Progress Energy. You will meet a few of our many talented employees in this report. More than 10,000 others have their own stories to tell.

I'm proud of this company's legacy of safety, integrity and service. We are building on that record while being innovative in meeting the new energy realities of 2008 and beyond. Our employees are savvy about the changes in our industry and are deeply committed to our service mission. They feel the responsibility of having millions of people depend on us every hour of every day.

The way our people strive to produce operational excellence day after day and superior financial results year after year inspires me. Together, we're creating a great place to work for all kinds of people willing to perform to high standards – a place where we treat everyone with dignity, respect and fairness, and engage everyone in securing a strong future.

Before ending this letter, I want to say a word about Bob McGehee, our chairman and CEO who died suddenly last October, just months before retiring. Bob was a kind, gracious man, insightful about this business and about life. He was an important mentor to me. As always, he had planned well and had this company ready for a smooth leadership transition.

Now, more than five months later, I think Bob would be proud of what we're doing to build on Progress Energy's positive momentum: the additional steps we're taking to prepare for the future and the responsible leadership we're showing in tackling the hard issues such as climate change.

I am privileged to be in this position, surrounded by a capable, forward-looking team, at this point in the history of our company and industry. I am energized by what we can accomplish for our company, for the communities we serve and for all who rely on us.

William D. Johnson

William D. Johnson
Chairman, President and Chief Executive Officer
March 2008

A LEGACY OF EXCELLENCE

A Tribute To Bob McGehee

CHAIRMAN AND CEO OF PROGRESS ENERGY, 2004 – 2007

Bob McGehee joined Progress Energy, then CP&L, in 1997. Both wise and humble, he possessed the rare ability to engage meaningfully with employees, investors, customers and community leaders. Every day, he represented Progress Energy at its best through his personal example of integrity and caring.

With a clear strategic focus and steady hand, Bob McGehee navigated Progress Energy through a period of tremendous change in the industry and the company itself. Under his leadership, the company successfully divested noncore subsidiaries to focus on our two regulated utilities, bringing both to a level of industry-recognized excellence. He also guided the development of a long-term strategic plan to maintain our track record of operational excellence, environmental responsibility and customer commitment. His legacy of excellence will continue as a vital part of Progress Energy's future.

"I've always focused on the job at hand and tried to do my very best."

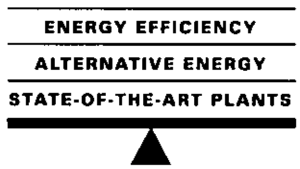
–Bob McGehee

LOOKING AT ENERGY EFFICIENCY IN A NEW LIGHT.

Energy efficiency succeeds on many levels. We partner with our customers to develop the energy-efficiency programs that work for their lifestyles – and save them money every day.

— Chris Edge
Manager, DSM and Alternative Energy Strategies
Progress Energy Carolinas

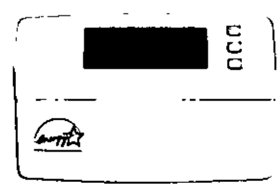
A CHANGING ENERGY LANDSCAPE. Clean, reliable, affordable power is our fundamental commitment. Today we face new energy realities, including rising energy prices and environmental concerns. But at Progress Energy, we continue to excel at our fundamental commitment – and our innovative Balanced Solution strategy is the reason.



A STRONG EMPHASIS ON ENERGY EFFICIENCY. We are developing a bold new role for energy efficiency – one that benefits our customers, the environment and our business. In the past, energy efficiency and financial success were often seen as incompatible for an electric utility. But through thoughtful, consensus-based strategies, we're making energy efficiency an important and viable component of today's energy solutions. In Florida, we continued working with the governor and other key leaders to further some of the country's most advanced thinking in energy efficiency, introducing 39 new programs in 2007. In North Carolina, we are aggressively expanding our portfolio of energy-efficiency programs. Our goal is to double the 1,000 megawatts currently being saved, an amount equivalent to the capacity of more than six combustion-turbine power plants.

PARTNERING WITH CUSTOMERS. Today's customers are increasingly concerned about their energy spending and eager for actionable information and resources. In 2007, we launched a dynamic communications platform, *Save The Watts*,™ which has engaged and motivated thousands of customers. This program uses a variety of media, including television, print and the Web, to raise customer awareness of energy-saving options and resources. This collaborative relationship with customers is a critical component of operational excellence in today's landscape. And it's the foundation upon which we build constructive regulatory and public policy so we can continue excelling at the fundamentals far into the future.

Meet our innovative "spokesbulb," Save The Watts *guy. He's on TV, the radio, even the Web, helping customers make smart energy choices.*



We're looking at the latest advances, including smart thermostats, to help our customers make better energy choices.

Throughout our service areas, we've been partnering with The Home Depot to raise awareness of new energy-saving options and offer CFLs at reduced prices.

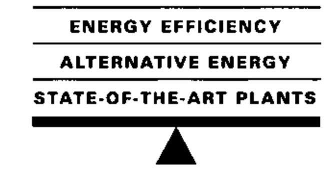
We're investing in new technologies like SmartGrid that will make our distribution system more efficient and effective for our customers.

LOOKING AT ALTERNATIVE ENERGY IN A NEW LIGHT.

Tomorrow's energy breakthroughs are being developed today. It's exciting to be a part of advancing the policies that will make them more successful.

— Caroline Choi
Director, Energy Policy and Strategy
Progress Energy

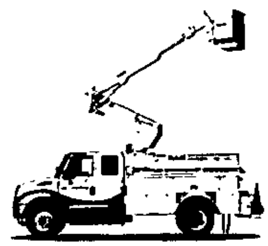
DEVELOPING VIABLE ALTERNATIVES. The second component of our Balanced Solution strategy is increased support for alternative energy. By working collaboratively with all stakeholders, from scientists to entrepreneurs, we are developing exciting and feasible alternative energy options – options that make sense for the environment and our bottom line.



PURSUING NEW TECHNOLOGIES, NEW OPTIONS. Progress Energy is committed to increasing the proportion of renewables in our generation portfolio to help offset the need for new power plants, reduce greenhouse gas emissions and further the development of reliable and affordable alternative energy options for the future. In 2007, we issued a request for proposals, seeking viable, cost-effective renewable energy projects. Some of the options we're considering include solar photovoltaic, hydrogen, hydropower, geothermal, landfill methane gas and biomass such as poultry or hog waste. In the Carolinas, we are buying up to 1 million megawatt hours of renewable energy from various sources – equivalent to the annual needs of about 70,000 households. In Florida, we have invested in several new options, including three promising biomass projects from which we expect to buy 267 megawatts of electricity over 20 years.

WORKING WITH OUR CUSTOMERS. Many of today's customers want tangible ways to support environmentally friendly solutions. In Florida, we recently added an incentive for solar water heating to our popular *EnergyWise*℠ program. Customers can save up to 85 percent on their water heating costs while reducing electrical demand and eliminating more than 25,000 pounds of carbon dioxide emissions over 20 years. Renewable energy sources such as this are a critical part of how we're meeting the new expectations of today's customers and securing a stronger energy future for us all.

In 2007, Progress Energy was named to the Dow Jones Sustainability Index for the third straight year.



Progress Energy is taking our alternative energy message to the streets with hybrid bucket trucks and other fuel-efficient, low-emissions vehicles.

We're supporting tomorrow's energy leaders today with energy education grants and our new SolarWise for Schools *program.*

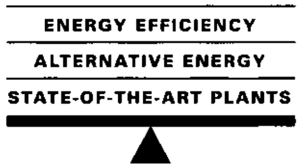
Supporting alternative energy is one of the smartest, most sustainable ways to continue delivering clean, reliable, affordable power today – and tomorrow.

LOOKING AT POWER GENERATION IN A NEW LIGHT.

Like the parts of an intricate, efficient machine, the people at our generating plants work together to ensure safe and reliable operations.

— *Rufus Jackson*
Plant Manager, Anclote
Progress Energy Florida

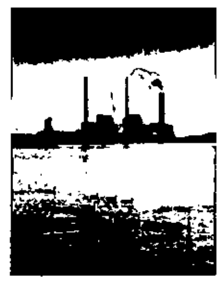
A RELIABLE COMBINATION. Every part of our Balanced Solution must work together. For our company to continue delivering clean, reliable, affordable power, we must combine energy efficiency and alternative energy with proven sources of large-scale power generation that are safe, cost-efficient and environmentally responsible.



UPGRADING EXISTING PLANTS. We have a long history of operational excellence, and we continue to invest in our plants to maintain that record and at the same time address growing environmental concerns and volatility in fuel pricing and availability. We have installed "scrubber" technology on four coal-fired units, reducing emissions and making them among the cleanest in the country. And we are applying lessons learned from the highly successful Brunswick Nuclear Plant uprate, the first in the country to achieve 120 percent of its original rated capacity, to bring similar improvements in efficiency across our generation fleet.

STATE-OF-THE-ART NUCLEAR GENERATION. Today we face several new energy realities: growing population and energy demand, the need to reduce greenhouse gas emissions and address global climate change, and concerns over dependence on fossil fuel. At Progress Energy, we believe strongly that new nuclear is a good option for addressing these issues. We have chosen two sites (Levy County, Fla., and the Harris Plant in North Carolina) as our preferred locations if the decision to build new nuclear plants is made. And we are working closely with our communities as we refine our future plans. Having completed our strategy of divesting noncore assets, we are confident that if we do move forward, we will have the focus and the resources to bring these large and complex projects to a safe, timely and well-managed conclusion.

We're using the latest technology to improve both the way we generate power and the way we transmit it.



State-of-the-art investments are helping us reduce emissions and increase efficiency throughout our fleet of power plants.

Advanced technology requires skilled workers. Our Power Careers Program prepares workers for the challenges ahead.

We are working collaboratively with all stakeholders through groups like the Community Energy Advisory Council (CEAC) in the Carolinas Western Region.

WORKING TOGETHER FOR A BRIGHT FUTURE.

At Progress Energy, we are more than 10,000 people with one mission: to deliver the most responsible, affordable and innovative solutions for today's changing energy landscape. Together we have streamlined and centered our business so each of us can concentrate on what we know and do best: the regulated electric utility business. We are reaching out across the company and throughout our communities, building collaborative solutions to the benefit of all stakeholders. And every day, in everything we do, we are looking at power in a new light – seeking out the smartest, most innovative ways to continue our track record of operational excellence in the face of today's changing energy needs. The result is increasing value for our shareholders, better service for our customers and communities – and a strong, sustainable future for all of us.

Strong leadership helps us excel.

THE RIGHT BALANCE FOR SUCCESS

On track to be the country's largest "pure play" regulated electric utility.

Balanced Solution for the changing energy landscape.

Growing customer base and investment opportunities.

Motivated employees dedicated to operational excellence.

Constructive community relations and regulatory environments.

Committed to our communities – $10.8 million invested in 2007.

Boosted economic development, bringing $951 million and 10,400 jobs to our communities.

20th straight year of increasing dividends.

Strong earnings per share growth.

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.

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; Operations and Nuclear Oversight.

David L. Burner
Retired Chairman and Chief Executive Officer, Goodrich Corp. (aerospace components, systems and services)
Darby, Mont.

Elected to the board in 1999 and sits on the following committees: Corporate Governance; Finance (Chair); Organization and Compensation.

Richard L. Daugherty
Formerly Executive Director, NCSU Research Corp., Vice President, IBM PC Company and Senior State Executive, IBM Corp.
Raleigh, N.C.

Elected to the board in 1992 and sits on the following committees: Audit and Corporate Performance (Chair); Corporate Governance; Finance.

E. Marie McKee
Senior Vice President, Corning, Inc. (manufacturer of components for high-technology systems for consumer electronics, mobile emissions controls, telecommunications and life sciences) and President and Chief Executive Officer, Steuben Glass
Corning, N.Y.

Elected to the board in 1999 and sits on the following committees: Corporate Governance; 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 Investments, Inc. (global provider of value added services and technology to the nuclear generation industry worldwide)
Lynchburg, Va.

Elected to the board in 2007 and sits on the following committees: Audit and Corporate Performance; Operations and Nuclear Oversight.

Harris E. DeLoach, Jr.
Chairman, President 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; Operations and Nuclear Oversight (Chair); Organization and Compensation.

Robert W. Jones
Senior Advisor, Morgan Stanley (global provider of financial services to companies, governments and investors)
Bedford, N.Y.

Elected to the board in 2007 and sits on the following committees: Finance; Organization and Compensation.

W. Steven Jones
Dean and Professor of Management of Kenan-Flagler Business School at the University of North Carolina at Chapel Hill
Chapel Hill, N.C.

Elected to the board in 2005 and sits on the following committees: Operations and Nuclear Oversight; Organization and Compensation.

Carlos A. Saladrigas
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; Finance.

Alfred C. Tollison, Jr.
Retired Chairman and Chief Executive Officer, Institute of Nuclear Power Operations (INPO is a nuclear industry-sponsored nonprofit organization)
Marietta, Ga.

Elected to the board in 2006 and sits on the following committees: Audit and Corporate Performance; Operations and Nuclear Oversight.

Jeffrey Jenkins, first class Line and Service technician, Progress Energy Carolin

Progress Energy achieved full compliance with the applicable internal control requirements in connection with its 2007 financial reporting processes.

RESPONSIBILITIES OF BOARD COMMITTEES

AUDIT AND CORPORATE PERFORMANCE COMMITTEE

This committee reviews the annual and quarterly financial results of the company and the various periodic reports the company files with the Securities and Exchange Commission. It is responsible for retaining the company's external auditors, overseeing and monitoring the auditors' activities and pre-approving all external audit and non-audit services and fees. This committee also oversees the activities of the internal audit department and the Corporate Ethics Program.

CORPORATE GOVERNANCE COMMITTEE

This committee is responsible for making recommendations on the structure, charter, practices and policies of the board, including amendments to the articles of incorporation and bylaws. The committee ensures that processes are in place for annual CEO performance appraisal, reviews of succession planning and management development. It also recommends the process for the annual assessment of board performance and criteria for board membership. In addition, it proposes nominees to the board.

FINANCE COMMITTEE

This committee reviews and oversees the company's financial policies and planning and the company's pension funds. It monitors the company's financial position, reviews the company's strategic investments and financing options, and recommends changes in the company's dividend policy.

OPERATIONS AND NUCLEAR OVERSIGHT COMMITTEE

This committee reviews the company's load forecasts and plans for generation, transmission and distribution, fuel procurement and transportation, customer service, energy trading, term marketing and other company operations with a particular emphasis on nuclear operations. The committee ensures company policies, procedures and practices relative to environmental protection and safety-related issues are sufficient to achieve and maintain compliance with applicable laws and regulations, and advises and makes recommendations to the board regarding these matters.

ORGANIZATION AND COMPENSATION COMMITTEE

This committee reviews personnel policies and procedures for consistency with governmental rules and regulations and ensures that the company attracts and retains competent, talented employees. The committee reviews all executive development and management-succession plans, evaluates CEO performance and makes senior executive compensation decisions.

EXECUTIVE AND SENIOR OFFICERS

William D. Johnson
Chairman, President and Chief Executive Officer

Peter M. Scott III
Executive Vice President and Chief Financial Officer
Progress Energy, Inc.
President and Chief Executive Officer
Progress Energy Service Company, LLC

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

Jeffrey J. Lyash
President and Chief Executive Officer
Progress Energy Florida, 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.

John R. McArthur
Senior Vice President – Corporate Relations
General Counsel and Secretary

Mark F. Mulhern
Senior Vice President – Finance
Progress Energy Service Company, LLC

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

Paula J. Sims
Senior Vice President – Power Operations
Progress Energy Carolinas, Inc.
Progress Energy Florida, Inc.

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) "Strategy" about our future strategy and goals; b) "Results of Operations" about trends and uncertainties; c) "Liquidity and Capital Resources" about operating cash flows, estimated capital requirements through the year 2010 and future financing plans; and d) "Other Matters" about our synthetic fuels tax credits, the effects of new environmental regulations, nuclear decommissioning costs and changes in the regulatory environment.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex laws and regulations, including those relating to the environment and the Energy Policy Act of 2005 (EPACT); the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; the financial resources and capital needed to comply with environmental laws and renewable energy portfolio standards and our ability to recover related eligible costs under cost-recovery clauses or base rates; our ability to meet current and future renewable energy requirements; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the impact on our facilities and businesses from a terrorist attack; 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; economic fluctuations and the corresponding impact on our customers, including downturns in the housing and consumer credit markets; 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 (O&M) and large construction projects; the ability of our subsidiaries to pay upstream dividends or distributions to the Parent; the ability to successfully access capital markets on favorable terms; the impact that increases in leverage may have on us; our ability to maintain our current credit ratings and the impact on our financial condition and ability to meet our cash and other financial obligations in the event our credit ratings are downgraded; 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); the investment performance of our nuclear decommissioning trust funds and assets of pension and benefit plans; the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements; and unanticipated changes in operating expenses and capital expenditures. Many of these risks similarly impact our nonreporting subsidiaries.

These and other risk factors are detailed from time to time in our filings with the United States Securities and Exchange Commission (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 it assess the effect of each such factor on Progress Energy.

The following 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 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 and Progress Energy Florida, as the "Utilities." MD&A should be read in conjunction with the Progress Energy Consolidated Financial Statements.

INTRODUCTION

Our reportable business segments and their primary operations include:

- Progress Energy Carolinas (PEC) – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina; and
- Progress Energy Florida (PEF) – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida.

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 business segment.

Strategy

We are an integrated energy company primarily focused on the end-use electricity markets. Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses. Our two electric utilities operate in regulated retail utility markets in the southeastern United States and have access to robust wholesale markets in the eastern United States, which we believe positions us well for long-term growth. We are focused on the following key priorities:

- consistently excelling in the daily fundamentals of our utility business, including safely and reliably generating and delivering power to our customers;
- successfully implementing our balanced solution to responsibly address demand growth and climate change;
- maintaining constructive regulatory relations; and
- achieving our financial objectives year after year.

The Utilities operate in the southeastern United States, one of the fastest-growing regions of the country, and had a net increase of approximately 51,000 customers over the past year. Despite our anticipated customer growth, the Utilities are subject to economic fluctuations and the corresponding impact on our customers, including downturns in the housing and consumer credit markets. Under normal weather conditions, we anticipate approximately 1.5 percent to 2.0 percent annual retail kilowatt-hour (kWh) sales growth at PEC and approximately 2.0 percent to 2.5 percent annual retail kWh sales growth at PEF in 2008. The Utilities seek a mix of 80 percent retail and 20 percent wholesale. The Utilities are focused on maintaining their regulated wholesale business through targeted contract renewals and origination opportunities.

We are implementing a comprehensive plan to meet the anticipated demand in the Utilities' service territories by focusing on energy efficiency, alternative energy and state-of-the-art power generation. First, we are enhancing our demand-side management (DSM), energy-efficiency and energy conservation programs. Recent legislation in North Carolina and Florida provides recovery for eligible costs of these programs. Second, we are pursuing renewable and alternative energy to increase the proportion of renewable and alternative energy sources in our generation portfolio. Recent legislation in North Carolina established a minimum renewable energy portfolio standard beginning in 2012. Executive orders issued by the governor of Florida address the reduction of greenhouse gas emissions and may lead to renewable energy standards in Florida. The Utilities have requested proposals for alternative energy sources, and options being considered include conversion of waste (such as wood, scrap tires and landfill gas) to energy, biomass as well as investments in solar and fuel cell programs. Third, we are evaluating new generation and fleet upgrades as we estimate that we will require new baseload generation facilities at both PEC and PEF toward the end of the next decade. We are evaluating the best available options for new generation, including advanced design nuclear technology, gas-fired combined cycle and combustion turbines, and modernization of existing coal plants to use clean coal technology. The considerations that will factor into this decision include, but are not limited to, construction costs, fuel diversity, transmission and site availability, environmental impact, the rate impact to customers and our ability to obtain cost-effective financing.

On February 19, 2008, PEC filed its combined license (COL) application with the Nuclear Regulatory Commission (NRC) for two additional reactors at the Shearon Harris Nuclear Plant (Harris). We anticipate filing a COL application in 2008 to potentially construct new nuclear plants in Florida. Filing of a COL is not a commitment to build a nuclear plant but is a necessary step to keep open the option of building a plant or plants. If we decide to pursue nuclear expansion, favorable changes in the regulatory and construction processes have evolved in recent years, including standardized design, detailed design before construction, COL to build and operate, streamlined regulatory approval process, annual prudence reviews and cost-recovery mechanisms for pre-construction and financing costs. State regulatory processes are specific to each jurisdiction. Also, nuclear generation has recently gained greater public support as a reliable energy source that does not emit greenhouse gases. See "Other Matters – Nuclear Matters" for additional information.

We are subject to significant air quality regulations passed in 2005 by the United States Environmental Protection Agency (EPA) that affect our fossil fuel-fired generating facilities, the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR) and mercury regulation (see "Other Matters – Environmental Matters" for discussion regarding Clean Air Mercury Rule [CAMR]). Additionally, at PEC's coal-fired facilities in North Carolina, we are subject to the North Carolina Clean Smokestacks Act enacted in 2002 (Clean Smokestacks Act). Including estimated costs for CAIR, CAVR, mercury regulation and the Clean Smokestacks Act, we currently estimate that total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or pass-through clauses, could be in excess of $700 million at PEC and $1.9 billion at PEF through 2018, which corresponds to the latest emission reduction deadline. In addition, growing state, federal and international attention to global climate change may result in the regulation of carbon dioxide (CO_2) and other greenhouse gases. Reductions in CO_2 emissions to the levels specified by some 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.

The Utilities successfully resolved key state regulatory issues in 2007, including retail fuel recovery filings in all jurisdictions. PEF also received Federal Energy Regulatory Commission (FERC) approval of its revised Open Access Transmission Tariff (OATT), including a settlement agreement with major transmission customers. In addition to Florida energy legislation enacted in 2006 that included cost-recovery mechanisms supportive of nuclear expansion, North Carolina and South Carolina both enacted energy legislation in 2007. North Carolina's comprehensive energy bill included provisions for expanding the traditional fuel clause, renewable energy portfolio standards, recovery of qualified DSM and energy-efficiency programs and cost recovery during baseload generation construction. Key elements of South Carolina's energy law included expansion of the annual fuel clause and recovery mechanisms and streamlined regulatory processes supportive of nuclear expansion. As part of the Clean Smokestacks Act, PEC operated under a base rate freeze in North Carolina through 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation. As a result of its 2005 base rate proceeding, PEF's base rate settlement extends through 2009. See "Other Matters – Regulatory Environment" and Note 7 for further information.

We have several key financial objectives, the first of which is to achieve sustainable earnings growth. In addition, we seek to continue our track record of dividend growth, as we have increased our dividend for 20 consecutive years, and 32 of the last 33 years. We plan to continue our efforts to enhance balance sheet strength and flexibility so that we are positioned to accommodate the significant future growth expected at the Utilities. As of the end of 2007, our debt to total capitalization ratio was 53.3 percent. Our targeted debt to total capitalization ratio is 55 percent.

Our ability to meet these financial objectives is largely dependent on the earnings and cash flows of the Utilities. The Utilities' earnings and operating cash flows are heavily influenced by weather, the economy, demand for electricity related to customer growth, actions of regulatory agencies, cost controls, and the timing of recovery of fuel costs and storm damage. The Utilities contributed $813 million of our segment profit and generated substantially all of our consolidated cash flow from operations in 2007. Partially offsetting the Utilities' segment profit contribution were losses of $120 million recorded at Corporate and Other, primarily related to interest expense on holding company debt.

While the Utilities expect retail sales growth in the future, they are facing, and expect to continue to face, rising costs. The Utilities remain committed to minimizing the expected growth in operation and maintenance (O&M) expenses by effectively managing costs. The Utilities are allowed to recover prudently incurred fuel costs through the fuel portion of our rates, which are adjusted annually in each state. We are focused on mitigating the impact of rising fuel prices as the under-recovery of fuel costs impacts our cash flows, interest and leverage, and rising fuel costs and higher rates also impact customer satisfaction. Our efforts to mitigate these high fuel costs include our diverse generation mix, staggered fuel contracts and hedging, and supplier and transportation diversity.

We expect total capital expenditures (including expenditures for environmental compliance) for 2008, 2009 and 2010 to be approximately $2.8 billion, $2.9 billion and $2.8 billion, respectively. Subject to regulatory approval, applicable capital investments to support load growth and comply with environmental regulations increase the Utilities' "rate base" or investment in utility plant, upon which additional return can be realized, and create the basis for long-term earnings growth in the Utilities.

We expect to fund our business plans and new generation through operating cash flows and a combination of long-term debt, preferred stock and common equity, all of which are dependent on our ability to successfully access capital markets. We may also 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.

Our synthetic fuels operations have historically provided significant net earnings driven by the Section 29/45K tax credit program, which expired at the end of 2007. In accordance with our decision to permanently cease production of synthetic fuels, we abandoned our majority-owned facilities in the fourth quarter of 2007. The operations of our synthetic fuels businesses were reclassified to discontinued operations in 2007. However, the associated cash flow benefits from synthetic fuels are expected to come in the future when deferred Section 29/45K tax credits generated through December 31, 2007, but not yet utilized, are ultimately utilized. At December 31, 2007, the amount of these deferred tax credits carried forward was $830 million. See "Other Matters – Synthetic Fuels Tax Credits" below and Note 22D for additional information on our synthetic fuels tax credits and other matters.

As discussed more fully in Note 3 and "Results of Operations – Discontinued Operations," in accordance with our business strategy to reduce our business risk and to focus on the core operations of the Utilities, the majority of our nonregulated business operations have been divested or are in the process of being divested. These operations have been classified as discontinued operations in the accompanying financial statements. Consequently, the composition of other continuing segments has been impacted by these divestitures.

RESULTS OF OPERATIONS

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

Overview

FOR 2007 AS COMPARED TO 2006 AND 2006 AS COMPARED TO 2005

For the year ended December 31, 2007, our net income was $504 million or $1.97 per share compared to $571 million or $2.28 per share for the same period in 2006. For the year ended December 31, 2007, our income from continuing operations was $693 million compared to $551 million for the same period in 2006. The increase in income from continuing operations as compared to prior year was due primarily to:

- lower Clean Smokestacks Act amortization expense at PEC;
- lower interest expense at the Parent due to reducing debt in late 2006;
- the cost incurred to redeem debt at the Parent in 2006;
- favorable weather at PEC;
- lower allocations of corporate overhead to continuing operations as a result of the 2006 divestitures;
- unrealized losses recorded on contingent value obligations (CVOs) during 2006;
- favorable allowance for funds used during construction (AFUDC) equity at the Utilities;
- favorable growth and usage at the Utilities; and
- higher wholesale sales at PEF.

Partially offsetting these items were:

- higher O&M expenses at the Utilities primarily due to higher outage and maintenance costs and higher employee benefits;
- additional depreciation expense associated with PEC's accelerated cost-recovery program for nuclear generation assets (See Note 7B);

- higher interest expense at PEF;
- the impact of the 2006 gain on sale of Level 3 Communications, Inc. (Level 3) stock acquired as part of the divestiture of Progress Telecom, LLC (PT LLC); and
- higher other operating expenses due to disallowed fuel costs at PEF.

For the year ended December 31, 2006, our net income was $571 million or $2.28 per share compared to $697 million or $2.82 per share for the same period in 2005. For the year ended December 31, 2006, our income from continuing operations was $551 million compared to $523 million for the same period in 2005. The increase in income from continuing operations as compared to prior year was due primarily to:

- prior year postretirement and severance expenses related to the 2005 cost-management initiative;
- increased retail growth and usage at the Utilities;
- the gain on sale of Level 3 stock acquired as part of the divestiture of PT LLC; and
- the prior year write-off of unrecoverable storm costs at PEF.

Partially offsetting these items were:

- unfavorable weather at the Utilities;
- the cost incurred to redeem debt at the Parent;
- unrealized losses recorded on CVOs;
- increased nuclear outage expenses at PEC; and
- the prior year gain on the sale of PEF's utility distribution assets serving the City of Winter Park, Fla. (Winter Park).

Our segments contributed the following profit or loss from continuing operations:

(in millions)	2007	Change	2006	Change	2005
PEC	$498	$44	$454	$(36)	$490
PEF	315	(11)	326	68	258
Total segment profit	813	33	780	32	748
Corporate and Other	(120)	109	(229)	(4)	(225)
Total income from continuing operations	693	142	551	28	523
Discontinued operations, net of tax	(189)	(209)	20	(153)	173
Cumulative effect of change in accounting principle, net of tax	–	–	–	(1)	1
Net income	$504	$(67)	$571	$(126)	$697

COST-MANAGEMENT INITIATIVE

On February 28, 2005, we approved a workforce restructuring that resulted in a reduction of approximately 450 positions. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program. In connection with this initiative, we incurred approximately $164 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005, of which $5 million has been reclassified to discontinued operations. We did not incur similar charges during 2007 or 2006. The severance and postretirement charges are primarily included in O&M expense on the Consolidated Statements of Income and will be paid over time.

Progress Energy Carolinas

PEC contributed segment profits of $498 million, $454 million and $490 million in 2007, 2006 and 2005, respectively. The increase in profits for 2007 as compared to 2006 is primarily due to lower Clean Smokestacks Act amortization, the favorable impact of weather and favorable retail customer growth and usage, partially offset by higher O&M expenses related to plant outage and maintenance costs and employee benefit costs and additional depreciation expense associated with PEC's accelerated cost-recovery program for nuclear generating assets.

The decrease in profits for 2006 as compared to 2005 is primarily due to the unfavorable impact of weather, higher O&M expense related to nuclear outages, the impact of suspending the allocation of the Parent's income tax benefit not related to acquisition interest expense and 2006 capital project write-offs. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006. These were partially offset by postretirement and severance expenses incurred in 2005 and favorable retail customer growth and usage.

The revenue tables below present the total amount and percentage change of revenues excluding fuel. Revenues excluding fuel is defined as total electric revenues less fuel revenues. We consider revenues excluding fuel a useful measure to evaluate PEC's electric operations because fuel revenues primarily represent the recovery of fuel and a portion of purchased power expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. We have included the analysis below as a complement to the financial information we provide in accordance with accounting principles generally accepted in the United States of America (GAAP). However, revenues excluding fuel are not defined under GAAP, and the presentation may not be comparable to other companies' presentation or more useful than the GAAP information provided elsewhere in this report.

REVENUES

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

(in millions) Customer Class	2007	% Change	2006	% Change	2005
Residential	**$1,613**	10.3	$1,462	2.8	$1,422
Commercial	**1,107**	10.3	1,004	6.8	940
Industrial	**716**	0.7	711	3.9	684
Governmental	**98**	7.7	91	4.6	87
Total retail revenues	**3,534**	8.1	3,268	4.3	3,133
Wholesale	**754**	4.7	720	(5.1)	759
Unbilled	**–**	–	(1)	–	4
Miscellaneous	**96**	(2.0)	98	4.3	94
Total electric revenues	**4,384**	7.3	4,085	2.4	3,990
Less: Fuel revenues	**(1,524)**	–	(1,314)	–	(1,186)
Revenues excluding fuel	**$2,860**	3.2	$2,771	(1.2)	$2,804

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

(in thousands of MWh) Customer Class	2007	% Change	2006	% Change	2005
Residential	**17,200**	5.8	16,259	(2.4)	16,664
Commercial	**14,032**	5.0	13,358	0.3	13,313
Industrial	**11,901**	(4.0)	12,393	(2.5)	12,716
Governmental	**1,438**	1.3	1,419	0.6	1,410
Total retail energy sales	**44,571**	2.6	43,429	(1.5)	44,103
Wholesale	**15,309**	5.0	14,584	(6.9)	15,673
Unbilled	**(55)**	–	(137)	–	(235)
Total MWh sales	**59,825**	3.4	57,876	(2.8)	59,541

PEC's revenues, excluding fuel revenues of $1.524 billion and $1.314 billion for 2007 and 2006, respectively, increased $89 million. The increase in revenues was due primarily to the $57 million favorable impact of weather and a $22 million favorable impact of retail customer growth and usage. Weather had a favorable impact as cooling degree days were 20 percent higher than 2006. Cooling degree days were 16 percent higher than normal. The favorable retail customer growth and usage was driven by an approximate increase in the average number of customers of 28,000 as of December 31, 2007, compared to December 31, 2006.

Industrial electric energy sales decreased in 2007 compared to 2006 primarily due to continued reduction 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 residential construction. The increase in industrial revenues for 2007 compared to 2006 is due to an increase in fuel revenues as a result of higher energy costs and the recovery of prior year fuel costs.

PEC's revenues, excluding fuel revenues of $1.314 billion and $1.186 billion for 2006 and 2005, respectively, decreased $33 million. The decrease in revenues was due primarily to the $67 million unfavorable impact of weather partially offset by a $24 million favorable impact of retail customer growth and usage. Weather had an unfavorable impact as cooling degree days were 9 percent below 2005 and heating degree days were 12 percent below 2005. The increase in retail customer growth and usage was driven by an approximate increase in the average number of customers of 29,000 as of December 31, 2006, compared to December 31, 2005. Although the change in wholesale revenue less fuel did not have a material impact on the change in revenues, wholesale electric energy sales were down 6.9 percent primarily due to lower excess generation sales in 2006 compared to 2005, partially offset by an increase in contracted wholesale capacity. The decrease in excess generation sales in 2006 compared to 2005 is due to favorable market conditions during 2005 that resulted in strong sales to the mid-Atlantic United States.

Industrial electric energy sales decreased in 2006 compared to 2005 primarily due to continued reduction in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation. The increase in industrial revenues for 2006 compared to 2005 is due to an increase in fuel revenues as a result of higher energy costs and the recovery of prior year fuel costs.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation, as well as energy purchased in the market to meet customer load. Fuel and 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.

Fuel and purchased power expenses were $1.683 billion for 2007, which represents a $176 million increase compared to 2006. Fuel used in electric generation increased $208 million to $1.381 billion compared to 2006. This increase is primarily due to a $156 million increase in fuel used in generation and a $54 million increase in deferred fuel expense. Fuel used in generation increased primarily due to a change in generation mix as the percentage of generation supplied by natural gas increased in response to plant outages and higher system requirements driven by favorable weather. Deferred fuel expense increased primarily due to the collection of fuel costs from customers that had been previously under-recovered. Purchased power expenses decreased $32 million to $302 million compared to prior year. The decrease in purchased power is due to lower cogeneration as a result of contract changes with one of PEC's co-generators.

Fuel and purchased power expenses were $1.507 billion for 2006, which represents a $117 million increase compared to 2005. Fuel used in electric generation increased $137 million to $1.173 billion compared to 2005. This increase is due to a $141 million increase in deferred fuel expense partially offset by a $5 million decrease in fuel used in generation. Deferred fuel expense increased primarily due to the collection of fuel costs from customers that had been previously under-recovered. Fuel used in generation decreased primarily due to lower system requirements. Purchased power expenses decreased $20 million to $334 million compared to prior year. The decrease in purchased power is due primarily to a change in volume as a result of lower system requirements.

Operation and Maintenance

O&M expenses were $1.024 billion for 2007, which represents a $94 million increase compared to 2006. This increase is driven primarily by the $49 million higher plant outage and maintenance costs (partially due to three nuclear outages in the current year compared to only two in the prior year) and $29 million due to higher employee benefit costs. The higher employee benefit costs are primarily due to current year changes in equity compensation plans and higher relative employee incentive goal achievement in 2007 compared to 2006. We do not expect the increase related to changes in equity compensation plans to continue in 2008.

O&M expenses were $930 million for 2006, which represents an $11 million decrease compared to 2005. This decrease is driven primarily by the $55 million impact of postretirement and severance expenses incurred in 2005 related to the cost-management initiative partially offset by $30 million of higher 2006 outage expenses at nuclear plants and capital project write-offs of $16 million in 2006.

Depreciation and Amortization

Depreciation and amortization expense was $519 million for 2007, which represents a $52 million decrease compared to 2006. This decrease is primarily attributable to a $106 million decrease in the Clean Smokestacks Act amortization, partially offset by $37 million additional depreciation associated with the accelerated cost-recovery program for nuclear generating assets (See Note 7B), $11 million charge to reduce PEC's GridSouth Transco, LLC (GridSouth) regional transmission organization (RTO) development costs (See Note 7D) and the $7 million impact of depreciable asset base increases. We recorded $34 million of Clean Smokestacks Act amortization during 2007 compared to $140 million in 2006 (See Note 7B). We recorded $37 million of additional depreciation associated with the accelerated cost-recovery program for nuclear generating assets during 2007 compared to none in 2006.

Depreciation and amortization expense was $571 million for 2006, which represents a $10 million increase compared to 2005. This increase is primarily attributable to the $12 million impact of depreciable asset base increases and $3 million of deferred environmental cost amortization partially offset by a $7 million decrease in the Clean Smokestacks Act amortization. We recorded $140 million of Clean Smokestacks Act amortization during 2006 compared to $147 million in 2005.

Taxes Other than on Income

Taxes other than on income were $192 million, $191 million and $178 million for 2007, 2006 and 2005, respectively. The $13 million increase in 2006 compared to 2005 is primarily due to a $7 million increase in property taxes and a $6 million increase in gross receipts taxes related to higher revenue. 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 expenses consisted of gains of $2 million and $10 million in 2007 and 2005, respectively, primarily due to land sales. There were no gains from land sales in 2006.

Total Other Income (Expense)

Total other income (expense) was $37 million of income for 2007, which represents a $13 million decrease compared to 2006. This decrease is primarily due to the 2006 reclassification of $16 million of indemnification liability expenses incurred in 2005 for estimated capital costs associated with the Clean Smokestacks Act expected to be incurred in excess of the maximum billable costs to the joint owner. This expense was reclassified to Clean Smokestacks Act amortization and had no impact on 2006 earnings (See Note 21B). This decrease is partially offset by $6 million favorable AFUDC equity related to costs associated with certain large construction projects.

Total other income (expense) was $50 million of income for 2006, which represents a $57 million increase compared to 2005. This increase is primarily due to the $32 million impact of reclassifying $16 million of indemnification liability expenses incurred in 2005 for estimated capital costs associated with the Clean Smokestacks Act expected to be incurred in excess of the maximum billable costs to the joint owner. This expense was reclassified to Clean Smokestacks Act amortization and had no impact on 2006 earnings (See Note 21B). Interest income increased $17 million for 2006 compared to 2005 primarily due to investment interest and interest on under-recovered fuel costs. In addition, the change in other income (expense) includes a $4 million favorable impact related to recording an audit settlement with the FERC in 2005.

Total Interest Charges, Net

Total interest charges, net were $210 million for 2007, which represents a $5 million decrease compared to 2006. This decrease is primarily due to the $5 million impact of a decrease in average long-term debt and $3 million favorable AFUDC debt related to costs associated with certain large construction projects, partially offset by $2 million higher interest related to higher variable rates on pollution control obligations.

Total interest charges, net were $215 million for 2006, which represents a $23 million increase compared to 2005. This increase is primarily due to the $20 million impact of a net increase in average long-term debt.

Income Tax Expense

Income tax expense was $295 million, $265 million and $239 million in 2007, 2006 and 2005, respectively. The $30 million income tax expense increase in 2007 compared to 2006 is primarily due to the impact of higher pre-tax income. The $26 million income tax expense increase in 2006 compared to 2005 is primarily due to the allocation of $23 million of the Parent's tax benefit not related to acquisition interest expense in 2005 that was suspended in 2006. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006.

Progress Energy Florida

PEF contributed segment profits of $315 million, $326 million and $258 million in 2007, 2006 and 2005, respectively. The decrease in profits for 2007 as compared to 2006 is primarily due to higher O&M expenses related to plant outage and maintenance costs and employee benefit costs, higher interest expense, higher other operating expenses and higher depreciation and amortization expense excluding recoverable storm amortization, partially offset by favorable AFUDC and higher wholesale sales.

The increase in profits for 2006 as compared to 2005 is primarily due to the impact of postretirement and severance costs incurred in 2005, favorable retail customer growth and usage, an increase in rental and other miscellaneous service revenues and the impact of the 2005 write-off of unrecoverable storm costs. These were partially offset by the 2005 gain on the sale of the utility distribution assets serving Winter Park, the unfavorable impact of weather on revenues and the impact of suspending the allocation of the Parent's tax benefit not related to acquisition interest expense. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006.

The revenue tables below present the total amount and percentage change of revenues excluding fuel and other pass-through revenues. Revenues excluding fuel and other pass-through revenues is defined as total electric revenues less fuel and other pass-through revenues. We consider revenues excluding fuel and other pass-through revenues a useful measure to evaluate PEF's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, purchased power and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. We have included the analysis below as a complement to the financial information we provide in accordance with GAAP. However, revenues excluding fuel and other pass-through revenues are not defined under GAAP, and the presentation may not be comparable to other companies' presentation or more useful than the GAAP information provided elsewhere in this report.

REVENUES

PEF's electric revenues and the percentage change by year and by customer class were as follows:

(in millions) Customer Class	2007	% Change	2006	% Change	2005
Residential	$2,363	0.1	$2,361	18.0	$2,001
Commercial	1,153	0.1	1,152	21.5	948
Industrial	318	(8.1)	346	21.8	284
Governmental	304	1.0	301	24.4	242
Revenue sharing refund	–	–	1	–	(1)
Total retail revenues	4,138	(0.6)	4,161	19.8	3,474
Wholesale	434	36.1	319	(7.3)	344
Unbilled	4	–	(5)	–	(6)
Miscellaneous	173	5.5	164	14.7	143
Total electric revenues	4,749	2.4	4,639	17.3	3,955
Less: Fuel and other pass-through revenues	(3,109)	–	(3,038)	–	(2,385)
Revenues excluding fuel and other pass-through revenues	$1,640	2.4	$1,601	2.0	$1,570

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

(in thousands of MWh) Customer Class	2007	% Change	2006	% Change	2005
Residential	19,912	(0.5)	20,021	0.6	19,894
Commercial	12,183	1.7	11,975	0.3	11,945
Industrial	3,820	(8.2)	4,160	0.5	4,140
Governmental	3,367	2.8	3,276	2.4	3,198
Total retail energy sales	39,282	(0.4)	39,432	0.7	39,177
Wholesale	5,930	30.8	4,533	(17.0)	5,464
Unbilled	88	–	(234)	–	(205)
Total MWh sales	45,300	3.6	43,731	(1.6)	44,436

PEF's revenues, excluding fuel and other pass-through revenues of $3.109 billion and $3.038 billion for 2007 and 2006, respectively, increased $39 million. The increase in revenues is primarily due to increased wholesale revenues, favorable retail customer growth and usage and other miscellaneous service revenues. Wholesale revenues increased $29 million primarily due to the $21 million impact of increased capacity under contract with a major customer. The favorable retail customer growth and usage impact of $7 million was driven by an approximate average net increase in the number of customers of 23,000 as of December 31, 2007, compared to December 31, 2006, partially offset by lower average usage per customer. Other miscellaneous service revenues increased primarily due to increased electric property rental revenues of $6 million.

Industrial electric energy revenues and sales decreased in 2007 compared to 2006 primarily due to a change in the terms of an agreement with a major customer.

PEF's revenues, excluding fuel and other pass-through revenues of $3.038 billion and $2.385 billion for 2006 and 2005, respectively, increased $31 million. The increase in revenues is due to a favorable retail customer growth and usage impact of $25 million and a $21 million increase in rental and other miscellaneous service revenues partially offset by a $13 million unfavorable impact of weather. The favorable retail customer growth and usage was driven by an approximate increase in the average number of customers of 35,000 as of December 31, 2006, compared to December 31, 2005. The weather impact is primarily due to a 16 percent decrease in heating degree days compared to 2005.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchased for generation, as well as energy and capacity purchased in the market to meet customer load. Fuel, purchased power and capacity 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.

Fuel and purchased power expenses were $2.646 billion in 2007, which represents a $45 million increase compared to 2006. Purchased power expense increased $116 million to $882 million compared to 2006. This increase is primarily due to a $123 million increase in current year purchased power costs partially offset by a $6 million decrease in the recovery of deferred capacity costs. The increased current year purchased power costs are a result of higher interchange purchases of $87 million and higher capacity costs of $43 million primarily due to new contracts. Fuel used in electric generation decreased $71 million to $1.764 billion due to a $323 million decrease in deferred fuel expense partially offset by a $252 million increase in current year fuel costs due primarily to an increase in oil and natural gas prices. Deferred fuel expenses were higher in 2006 primarily due to the collection of fuel costs from customers that had been previously under-recovered.

Fuel and purchased power expenses were $2.601 billion in 2006, which represents a $584 million increase compared to 2005. Fuel used in electric generation increased $512 million due to a $552 million increase in deferred fuel expense resulting from an increase in the fuel recovery rates on January 1, 2006, as a result of fuel costs from customers that had been previously under-recovered. This was partially offset by a $41 million decrease in current year fuel costs due primarily to lower system requirements. Purchased power expense increased $72 million primarily due to a $48 million increase in current year purchased power costs resulting from higher market prices and a $23 million increase in the recovery of deferred capacity costs.

Operation and Maintenance

O&M expenses were $834 million in 2007, which represents a $150 million increase compared to 2006. The increase is primarily due to $46 million related to an increase in storm damage reserves from the one-year extension of the storm surcharge, which began August 2007 (See Note 7C) and $40 million related to higher environmental cost recovery (ECRC) and energy conservation cost recovery (ECCR) costs. Additionally, the increase is due to $27 million higher plant outage and maintenance costs and $12 million higher employee benefit costs. The higher employee benefit costs are primarily due to current year changes in equity compensation plans and higher relative employee incentive goal achievement in 2007 compared to 2006. We do not expect the increase related to changes in equity compensation plans to continue in 2008. The ECRC, ECCR and storm damage reserve expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings.

O&M expenses were $684 million in 2006, which represents a $168 million decrease compared to 2005. The decrease is primarily due to a $102 million impact of postretirement and severance costs in 2005, $24 million of lower ECRC expenses due to a decrease in emission allowances and lower recovery rates, $17 million related to the 2005 write-off of unrecoverable storm restoration costs (See Note 7C), a $9 million decrease in nuclear outage costs and the $6 million impact related to the 2005 write-off of GridFlorida RTO startup costs that were previously recovered in revenues.

Depreciation and Amortization

Depreciation and amortization expense was $366 million for 2007, which represents a decrease of $38 million compared to 2006, primarily due to $47 million lower amortization of storm restoration costs and $5 million lower software and franchise amortization, partially offset by the $13 million impact primarily related to depreciable asset base increases and a $7 million write-off of leasehold improvements, primarily related to vacated office space. Storm restoration costs, which were fully amortized in 2007, were recovered through the storm recovery surcharge and, therefore, have no material impact on earnings (See Note 7C).

Depreciation and amortization expense was $404 million for 2006, which represents an increase of $70 million compared to 2005, primarily due to a $72 million increase in the amortization of storm restoration costs and a $48 million increase in utility plant depreciation partially offset by a $51 million decrease in expenses related to cost of removal primarily due to rate changes resulting from the 2005 depreciation study effective January 1, 2006 (See Note 5D). As noted above, storm restoration cost amortization has no material impact on earnings.

Taxes Other than on Income

Taxes other than on income were $309 million for 2007 and 2006, and $279 million for 2005. The $30 million increase in 2006 compared to 2005 is primarily due to $18 million of higher gross receipts taxes and $14 million of higher franchise taxes, related to an increase in revenues, partially offset by lower payroll taxes. 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 expenses were $8 million in 2007 compared to a gain of $2 million in 2006. The $10 million difference is primarily due to the $12 million impact of a Florida Public Service Commission (FPSC) order requiring PEF to refund disallowed fuel costs to its ratepayers (See Note 7C).

Other operating expenses were a gain of $2 million in 2006 compared to a gain of $26 million in 2005. The decrease in the gain for 2006 compared to 2005 is primarily due to the $24 million gain on the sale of the utility distribution assets serving Winter Park recorded in 2005 (See Note 7C).

Total Other Income

Total other income was $48 million for 2007, which represents a $20 million increase compared to 2006. This increase is primarily due to $24 million favorable AFUDC equity related to costs associated with large construction projects, partially offset by $5 million lower interest income on unrecovered storm restoration costs. We expect AFUDC equity to continue to increase in 2008, primarily due to increased spending on environmental initiatives and other large construction projects. See "Future Liquidity and Capital Resources – Capital Expenditures."

Total other income was $28 million for 2006, which represents a $20 million increase compared to 2005. This increase is primarily due to $8 million of increased investment interest income and $6 million of interest on unrecovered storm restoration costs.

Total Interest Charges, Net

Total interest charges, net were $173 million in 2007, which represents an increase of $23 million compared to 2006. The increase in interest charges is primarily due to the $10 million impact of an increase in average long-term debt, the $7 million impact of interest on over-recovered fuel costs, $6 million increase in interest on income tax related items and $2 million increase related to the disallowed fuel costs (See Note 7C). These increases are partially offset by $7 million favorable AFUDC debt related to costs associated with large construction projects.

Total interest charges, net were $150 million in 2006, which represents an increase of $24 million compared to 2005. The increase in interest charges is primarily due to the $20 million impact of a net increase in average long-term debt.

Income Tax Expense

Income tax expense was $144 million, $193 million and $121 million in 2007, 2006 and 2005, respectively. The $49 million income tax expense decrease in 2007 compared to 2006 is primarily due to the $23 million impact of lower pre-tax income compared to the prior year, the $14 million impact of tax adjustments and the $9 million impact of favorable AFUDC equity discussed above. The tax adjustments are primarily related to the $11 million impact of changes in income tax estimates and the $3 million favorable impact related to the closure of certain federal tax years and positions. AFUDC equity is excluded from the calculation of income tax expense. The $72 million income tax expense increase in 2006 compared to 2005 is primarily due to changes in pre-tax income. In addition, 2005 income tax expense included the allocation of $13 million of the Parent's tax benefit not related to acquisition interest expense that was suspended in 2006. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006.

Corporate and Other

The Corporate and Other segment primarily includes the operations of the Parent, PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements as a separate business segment. Corporate and Other expense is summarized below:

(in millions)	2007	Change	2006	Change	2005
Other interest expense	$(205)	$54	$(259)	$(2)	$(257)
Contingent value obligations	(2)	23	(25)	(31)	6
Tax reallocation	–	–	–	38	(38)
Other income tax benefit	105	(14)	119	19	100
Other expense	(18)	46	(64)	(28)	(36)
Corporate and Other after-tax expense	$(120)	$109	$(229)	$(4)	$(225)

Other interest expense, which includes elimination entries, decreased $54 million for 2007 compared to 2006 primarily due to the $86 million impact of the $1.7 billion reduction in debt at the Parent during 2006, partially offset by a $45 million decrease in the interest allocated to discontinued operations. The decrease in interest expense allocated to discontinued operations resulted from the allocations of interest expense in 2006 for operations that were sold in 2006. Interest expense allocated to discontinued operations was $13 million and $58 million for 2007 and 2006, respectively.

Other interest expense, which includes elimination entries, increased $2 million for 2006 compared to 2005 primarily due to a $19 million decrease in the interest allocated to discontinued operations and a decrease in the elimination of intercompany interest expense due to lower intercompany debt balances partially offset by lower interest expense due to lower debt at the Parent. The decrease in interest expense allocated to discontinued operations resulted from the full year allocations of interest expense in 2005 compared to partial year allocations of interest in 2006 for operations that were sold in 2006. Interest expense allocated to discontinued operations was $58 million and $77 million for 2006 and 2005, respectively.

Progress Energy issued 98.6 million CVOs in connection with the acquisition of Florida Progress Corporation (Florida Progress) in 2000. Each CVO represents the right of the holder to receive contingent 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. At December 31, 2007, 2006 and 2005, the CVOs had a fair value of approximately $34 million, $32 million and $7 million, respectively. Progress Energy recorded unrealized losses of $2 million and $25 million for 2007 and 2006, respectively, and unrealized gains of $6 million for 2005, to record the changes in fair value of the CVOs, which had average unit prices of $0.35, $0.33 and $0.07 at December 31, 2007, 2006 and 2005, respectively.

For the years ended December 31, 2007 and 2006, income tax expense was not increased by the allocation of the Parent's income tax benefits not related to acquisition interest expense to profitable subsidiaries. Due to the repeal of the Public Utility Holding Company Act of 1935, as amended (PUHCA 1935), beginning in 2006 we no longer allocate the Parent income tax benefits not related to acquisition interest expense to profitable subsidiaries. Since 2002, Parent income tax benefits not related to acquisition interest expense were allocated to profitable subsidiaries, in accordance with a PUHCA 1935 order. For the year ended December 31, 2005, income tax expense was increased by $38 million due to the allocation of the Parent's income tax benefit.

Other income tax benefit decreased for 2007 compared to 2006 primarily due to decreased pre-tax expense at the Parent primarily as a result of the loss on early retirement of debt in 2006, partially offset by the $14 million impact related to the closure of certain federal tax years and positions (See Note 14), the $18 million impact of taxes on interest allocated to discontinued operations and the $5 million impact related to the deduction for domestic production activities. Other income tax benefit increased for 2006 compared to 2005 primarily due to increased pre-tax expense at the Parent and the $8 million impact of taxes on interest allocated to discontinued operations.

For 2007, other expense was $18 million compared to $64 million in 2006. The $46 million decrease is primarily due to the $59 million pre-tax loss on redemptions of debt at the Parent in 2006 (See Note 12) and the $30 million decrease in the allocation of corporate overhead as a result of the divestitures completed during 2006. These decreases are partially offset by the $17 million pre-tax gain, net of minority interest, on the sale of Level 3 stock subsequent to the sale of PT LLC in 2006 (See Note 3E) and the $14 million increase in interest income on temporary investments due to proceeds from the sale of nonregulated businesses. The $28 million increase in other expense from 2005 to 2006 was primarily due to the $59 million pre-tax loss on redemptions of debt at the Parent partially offset by the $17 million pre-tax gain, net of minority interest, on the sale of Level 3 stock subsequent to the sale of PT LLC. In addition, other expense changed due to a $14 million increase in interest income on temporary investments due to proceeds from the sale of DeSoto County Generating Co., LLC (DeSoto), Rowan County Power, LLC (Rowan) and our natural gas drilling and production business (Gas).

Discontinued Operations

Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses to focus on the core operations of the Utilities. We divested, or announced divestitures, of multiple nonregulated businesses during 2007 and 2006. Consequently, the composition of other continuing segments has been impacted by these divestitures.

CCO OPERATIONS

CCO – Georgia Operations

On March 9, 2007, our subsidiary Progress Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. Assets divested include approximately 1,900 MW of gas-fired generation assets in Georgia. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated loss of $226 million in December 2006. Based on the terms of the final agreement and post-closing adjustments, during the year ended December 31, 2007, we reversed $18 million after-tax of the impairment recorded in 2006 (See Note 3A).

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

CCO's operations generated net losses from discontinued operations of \$283 million, \$57 million and \$54 million in 2007, 2006 and 2005, respectively. Net losses from discontinued operations in 2007 primarily represent the \$349 million after-tax charge associated with exit costs, partially offset by unrealized mark-to-market gains related to dedesignated natural gas hedges. These hedges were dedesignated because management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 billion cubic feet of natural gas would be fulfilled. Therefore, cash flow hedge accounting was discontinued.

The increase in loss for 2006 compared to 2005 is primarily due to the \$64 million pre-tax impairment loss (\$42 million after-tax) on goodwill recognized in the first quarter of 2006 (See Note 8) and an increase in realized mark-to-market losses on gas hedges due to gas price volatility. This was partially offset by a higher gross margin related to serving the fixed price full requirements contracts that began in April 2005 and serving an increased load on a pre-existing contract in Georgia, and \$66 million pre-tax of unrealized mark-to-market gains related to the dedesignated natural gas hedges.

CCO – DeSoto and Rowan Generation Facilities

On May 2, 2006, our board of directors approved a plan to divest of two subsidiaries of PVI, DeSoto and Rowan. DeSoto owned a 320 MW dual-fuel combustion turbine electric generation facility in DeSoto County, Fla., and Rowan owned a 925 MW dual-fuel combined cycle and combustion turbine electric generation facility in Rowan County, N.C. On May 8, 2006, we entered into definitive agreements to sell DeSoto and Rowan, including certain existing power supply contracts, to Southern Power Company, a subsidiary of Southern Company, for a gross purchase price of approximately \$80 million and \$325 million, respectively. We used the proceeds from the sales to reduce debt and for other corporate purposes (See Note 3D).

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. Based on the gross proceeds associated with the sales, we recorded an after-tax loss on disposal of \$67 million during the year ended December 31, 2006. DeSoto and Rowan operations generated combined net earnings from discontinued operations of \$10 million and \$3 million for the years ended December 31, 2006 and 2005, respectively.

TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

On December 24, 2007, we signed an agreement to sell coal terminals and docks in West Virginia and Kentucky (Terminals) for \$71 million in gross cash proceeds. Terminals was previously reported as a component of our former Coal and Synthetic Fuels operating segment. The terminals have a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale are expected to be used for general corporate purposes (See Note 3B).

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Internal Revenue Code. The production and sale of these products qualified for federal income tax credits under Section 29/45K so long as certain requirements were satisfied (See "Other Matters – Synthetic Fuels Tax Credits"). On September 14, 2007, we idled production of synthetic fuels at our majority-owned fuels facilities due to the high level of oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007 and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. 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. In accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for Impairment or Disposal of Long-Lived Assets," a long-lived asset is abandoned when it ceases to be used. All periods have been restated to reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Terminals and synthetic fuels businesses generated net earnings from discontinued operations of \$83 million and \$198 million for the years ended December 31, 2007 and 2005, respectively. Net losses from discontinued operations for Terminals and synthetic fuels businesses were \$37 million for the year ended December 31, 2006.

The change in net loss from discontinued operations of \$37 million for the year ended December 31, 2006, to net earnings from discontinued operations of $83 million for the year ended December 31, 2007, is primarily due to increased tax credits generated due to higher production of coal-based solid synthetic fuels, unrealized mark-to-market gain on derivative contracts in 2007 and the impairment of synthetic fuels assets recorded in 2006. These favorable items are partially offset by an increase in the tax credit reserve due to the increase in production and the change in the relative oil prices, which indicated a higher estimated phase-out of tax credits, and lower margins due to the increase in coal-based solid synthetic fuels production.

The change in net earnings from discontinued operations of $198 million for the year ended December 31, 2005, to net loss from discontinued operations of $37 million for the year ended December 31, 2006, is primarily due to lower synthetic fuels production as a result of high oil prices, which increased the potential phase-out of tax credits and the impairment of synthetic fuels assets recorded in 2006.

GAS OPERATIONS

On October 2, 2006, we sold Gas to EXCO Resources, Inc. for approximately $1.1 billion in net proceeds. Gas included Winchester Production Company, Ltd. (Winchester Production), Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels. Proceeds from the sale have been used primarily to reduce holding company debt and for other corporate purposes (See Note 3C).

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

Gas operations generated net earnings from discontinued operations of $4 million, $82 million and $48 million for the years ended December 31, 2007, 2006 and 2005, respectively. The increase in net earnings from discontinued operations during 2006 is primarily due to increased production, higher market prices and mark-to-market gains on gas hedges.

PROGRESS TELECOM, LLC

On March 20, 2006, we completed the sale of PT LLC to Level 3. We received gross proceeds comprised of cash of $69 million and approximately 20 million shares of Level 3 common stock valued at an estimated $66 million on the date of the sale. Our net proceeds from the sale of $70 million, after consideration of minority interest, were used to reduce debt. Prior to the sale, we had a 51 percent interest in PT LLC (See Note 3E). See Note 20 for a discussion of the subsequent sale of the Level 3 stock in 2006.

Based on the net proceeds associated with the sale and after consideration of minority interest, we recorded an after-tax gain on disposal of $28 million during the year ended December 31, 2006. Net (loss) earnings from discontinued operations for PT LLC were a loss of $2 million and earnings of $4 million for the years ended December 31, 2006 and 2005, respectively.

DIXIE FUELS AND OTHER FUELS BUSINESS

On March 1, 2006, we sold Progress Fuels' 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units. Dixie Fuels primarily transports coal from the lower Mississippi River to Progress Energy's Crystal River Facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels during the year ended December 31, 2006. During the year ended December 31, 2007, we recorded an additional gain of $2 million primarily related to the expiration of indemnifications (See Note 3F).

Net earnings from discontinued operations for Dixie Fuels and other fuels business were $7 million and $5 million for the years ended December 31, 2006 and 2005, respectively.

COAL MINING BUSINESSES

Progress Fuels owned five subsidiaries engaged in the coal mining business. These businesses were previously included in our former Coal and Synthetic Fuels business segment. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an estimated after-tax loss of $10 million for the sale of these assets (See Note 3G).

On December 24, 2007, we signed an agreement to sell the remaining net assets of the coal mining business for gross cash proceeds of $23 million. These assets include Powell Mountain Coal Co. and Dulcimer Land Co., which consist of about 30,000 acres in Lee County, Va., and Harlan County, Ky. The property contains an estimated 40 million tons of high quality coal reserves.

Net losses from discontinued operations for the coal mining business were $11 million, $4 million and $11 million for the years ended December 31, 2007, 2006 and 2005, respectively.

PROGRESS RAIL

On March 24, 2005, we completed the sale of Progress Rail Services Corporation (Progress Rail) to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Cash proceeds from the sale were approximately $429 million, consisting of $405 million base proceeds plus a working capital adjustment. During the years ended December 31, 2006 and 2005, we recorded an estimated after-tax loss for the sale of these assets of $6 million and $25 million, respectively. Proceeds from the sale were used to reduce debt (See Note 3H).

Net earnings from discontinued operations for Progress Rail were $5 million for the year ended December 31, 2005.

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 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 with the Audit and Corporate Performance Committee (Audit Committee) of our board of directors.

Utility Regulation

As discussed in Note 7, 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. 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 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. See Note 7 for additional information related to the impact of utility regulation on our operations.

Asset Impairments

As discussed in Note 9, we evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever impairment indicators exist. Examples of these indicators include current period losses combined with a history of losses, a projection of continuing losses, a significant decrease in the market price of a long-lived asset group, or the likelihood that an asset group will be disposed of significantly prior to the end of its useful life. 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. Performing an impairment test on long-lived assets involves management's judgment in areas such as identifying circumstances indicating an impairment may exist, identifying and grouping affected assets at the appropriate level, and developing the undiscounted cash flows associated with the asset group. Estimates of future cash flows contemplate factors such as expected use of the assets, future production and sales levels, and expected fluctuations of prices of commodities sold and consumed. Therefore, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

The carrying value of our total utility plant, net is $16.612 billion at December 31, 2007. The carrying value of our total diversified business property, net is $6 million at December 31, 2007. In addition, we have certain diversified business property with a carrying value of $38 million at December 31, 2007, included in net assets to be divested (See Note 3I). 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.

Under the full-cost method of accounting for oil and gas properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. The ceiling test takes into consideration the prices of qualifying cash flow hedges as of the balance sheet date. If the ceiling (discounted revenues) does not exceed total capitalized costs, we are required to write-down capitalized costs to the ceiling. We performed this ceiling test calculation every quarter prior to the sale of the Gas Operations (See Note 3C). No write-downs were required in 2006 or 2005.

See discussion of synthetic fuels asset impairments in "Other Matters – Synthetic Fuels Tax Credits" and in Notes 8 and 9.

Goodwill

As discussed in Note 8, we account for goodwill in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), which requires that goodwill be tested for impairment at least annually and more frequently when indicators of impairment exist. For our utility segments, the goodwill impairment tests are performed at the utility operating segment level. We performed the annual goodwill impairment test for both the PEC and PEF segments in the second quarters of 2007 and 2006, each of which indicated no impairment. If the fair values for the utility segments were lower by 10 percent, there still would be no impact on the reported value of their goodwill.

The carrying amounts of goodwill at December 31, 2007 and 2006, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment.

We calculated the fair value of our segments and reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow methodology and published industry valuations and market data as supporting information. These calculations are dependent on subjective factors such as management's estimate of future cash flows and the selection of appropriate discount and growth rates. These underlying assumptions and estimates are made as of a point in time; subsequent changes, particularly changes in management's estimate of future cash flows and the discount rates, growth rates or the timing of market equilibrium, could result in a future impairment charge to goodwill.

Synthetic Fuels Tax Credits

Our former Coal and Synthetic Fuels segment was previously involved in the production and sale of coal-based solid synthetic fuels as defined under the Internal Revenue Code (See Note 3B). The production and sale of the synthetic fuels from these facilities qualified for tax credits under Section 29/45K if certain requirements were satisfied, including a requirement that the synthetic fuels differ significantly in chemical composition from the coal used to produce such synthetic fuels and that the synthetic fuels were produced from a facility placed in service before July 1, 1998. For 2005 and prior years, the amount of Section 29 credits that we were allowed to generate in any calendar year was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized through December 31, 2005, are carried forward indefinitely as deferred alternative minimum tax credits on the Consolidated Balance Sheets. For 2006 and 2007, in accordance with federal legislation, the Section 29 tax credits have been redesignated as a Section 45K general business credit, which removes the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a 20-year carry forward period. This provision allowed us to produce synthetic fuels at a higher level than we have historically produced, had we chosen to do so. The synthetic fuels tax credit program expired at the end of 2007.

In addition, Section 29/45K provided that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeded a certain threshold value (the Threshold Price), the amount of tax credits was reduced for that year. Also, if the Annual Average Price increased high enough (the Phase-out Price), the Section 29/45K tax credits were eliminated for that year. The Threshold Price and the Phase-out Price were adjusted annually for inflation. We estimate that the 2007 Annual Average Price will result in an approximate 70 percent phase-out of the synthetic fuels tax credits related to synthetic fuels production in 2007. This estimate is derived from our estimates of the 2007 Threshold Price and Phase-out Price of $57 per barrel and $71 per barrel, respectively, based on an estimated inflation adjustment for 2007. For 2007 synthetic fuels production, the 2007 Annual Average Price is not known until after the end of the year. We recorded the 2007 tax credits based on our estimates of what we believe the Annual Average Price will be for 2007. Any portion of the tax credits that were phased out based on the projected 2007 Annual Average Price exceeding the Threshold Price was not recorded.

See further discussion in "Other Matters – Synthetic Fuels Tax Credits."

Pension Costs

As discussed in Note 16A, we maintain qualified noncontributory defined benefit retirement (pension) plans. 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 an increase in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate used to present value future benefit payments, we increased the discount rate to approximately 6.20% at December 31, 2007, from approximately 5.95% at December 31, 2006, which will decrease the 2008 benefit costs recognized, 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. Plan assets performed well in 2007, with returns of approximately 13%. That positive asset performance will result in decreased pension costs in 2008, all other factors remaining constant. In addition, contributions to pension plan assets in 2007 and 2008 will result in decreased pension costs in 2008 due to increased asset returns, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2008 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2008 will be $10 million to $20 million, compared with $31 million recognized in 2007.

We have pension plan assets with a fair value of approximately $2.0 billion at December 31, 2007. Our expected rate of return on pension plan assets is 9.0%. We review this rate on a regular basis. Under SFAS No. 87, "Employer's Accounting for Pensions" (SFAS No. 87), the expected rate of return used in pension cost recognition is a long-term rate of return; therefore, we do not adjust that rate of return frequently. In 2005, we elected to lower our expected rate of return from 9.25% to 9.0%. The 9.0% rate of return represents the lower end of our future expected return range given our asset allocation policy. A 0.25% change in the expected rate of return for 2007 would have changed 2007 pension costs by approximately $4 million.

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 9.0% expected long-term rate of return is applied. SFAS No. 87 specifies that entities may use either fair value or an averaging method that recognizes changes in fair value over a period not to exceed five years, with the method selected applied on a consistent basis from year to year. 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

Progress Energy, Inc. is a holding company and, as such, has no revenue-generating operations of its own. Our primary cash needs at the Parent level are our common stock dividend and interest and principal payments on our $2.6 billion of senior unsecured debt. Our ability to meet these needs is dependent on the earnings and cash flows of the Utilities, and the ability of the Utilities to pay dividends or repay funds to us. As discussed under "Future Liquidity and Capital Resources" below, synthetic fuels tax credits provide an additional source of liquidity as those credits are realized. Our other significant cash requirements arise primarily from the capital-intensive nature of the Utilities' operations, including expenditures for environmental compliance. We rely upon our operating cash flow, primarily generated by the Utilities, commercial paper and bank facilities, and our ability to access the long-term debt and equity capital markets for sources of liquidity.

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 can lead to over- or under-recovery of fuel costs, as changes in fuel prices are not immediately reflected in fuel surcharges due to regulatory lag in setting the surcharges. As a result, fuel price volatility can be both a source of and a use of liquidity resources, depending on what phase of the cycle of price volatility we are experiencing. Changes in the Utilities' fuel and purchased power costs may affect the timing of cash flows, but not materially affect net income.

Effective February 8, 2006, the Energy Policy Act of 2005 (EPACT) provisions enacted the Public Utility Holding Company Act of 2005 (PUHCA 2005). Progress Energy is a registered public utility holding company subject to regulation by the FERC under PUHCA 2005, including provisions relating to the issuance and sale of securities and the establishment of intercompany extensions of credit (utility and nonutility money pools). PEC and PEF participate in the utility money pool, which allows the two utilities to lend to and borrow from each other. A nonutility money pool allows our nonregulated operations to lend to and borrow from each other. The Parent can lend money to the utility and nonutility money pools but cannot borrow funds. Pursuant to PUHCA 2005, utility holding companies are allowed to continue to engage in financings authorized by the SEC, provided the authorization orders have been filed with the FERC and the holding company continues to comply with such orders, terms and conditions. We have filed all such SEC orders with the FERC; therefore, we are permitted to continue all such financing transactions.

Cash from operations, asset sales, short-term and long-term debt and limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans are expected to fund capital expenditures and common stock dividends for 2008. For the fiscal year 2008, we expect to realize an aggregate amount of approximately $100 million from the sale of stock through these plans.

We believe our internal and external liquidity resources will be sufficient to fund our current business plans. Risk factors associated with credit facilities and credit ratings are discussed below.

Historical for 2007 as Compared to 2006 and 2006 as Compared to 2005

CASH FLOWS FROM OPERATIONS

Cash from operations is the primary source used to meet operating requirements and capital expenditures. The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2007, 2006 and 2005. Net cash provided by operating activities for the three years ended December 31, 2007, 2006 and 2005, was $1.252 billion, $2.001 billion, and $1.467 billion, respectively.

Cash from operating activities for 2007 decreased when compared with 2006. The $749 million decrease in operating cash flow was primarily due to $472 million in income tax impacts, largely driven by income tax payments related to the sale of Gas; the $347 million payment made to exit the Georgia contracts (See Note 3A); a $279 million decrease in the recovery of fuel costs; and $65 million in premiums paid for derivative contracts in our synthetic fuels businesses. These impacts were partially offset by a $157 million decrease in inventory purchases in 2007, primarily related to coal purchases at the Utilities; $106 million of working capital changes related to the divestiture of CCO; and $47 million in net refunds of cash collateral previously paid to counterparties on derivative contracts in the current year compared to $47 million in net cash payments in the prior year at PEF. The decrease in recovery of fuel costs is due to a $335 million decrease at PEF driven by the 2006 recovery of previously under-recovered fuel costs, partially offset by a $56 million increase in the recovery at PEC driven by the 2007 recovery of previously under-recovered fuel costs.

Cash from operating activities for 2006 increased when compared with 2005. The $534 million increase in operating cash flow was primarily due to a $713 million increase in the recovery of fuel costs at the Utilities, a $248 million increase from the change in accounts receivable, approximately $103 million of proceeds received from the restructuring of a long-term coal supply contract at our discontinued terminals operations, and $72 million related to recovery of storm restoration costs at PEF. These impacts were partially offset by $141 million related to a wholesale customer prepayment in 2005 at PEC, as discussed below, a $108 million decrease from the change in accounts payable and a $96 million net increase in tax payments in 2006 compared to 2005. The increase in recovery of fuel costs was largely driven by the recovery of previously under-recovered 2005 fuel costs. The $248 million change in accounts receivable included $147 million at PEC, principally driven by the timing of wholesale sales, and $47 million at PEF, primarily related to timing of receipts. The $108 million decrease from the change in accounts payable was primarily related to our discontinued and abandoned operations (See Note 3).

In November 2005, PEC entered into a contract with the Public Works Commission of the City of Fayetteville, North Carolina (PWC), in which the PWC prepaid $141 million in exchange for future capacity and energy power sales.

The prepayment covered approximately two years of electricity service and included a prepayment discount of approximately $16 million.

In 2007 and 2006, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. In 2005, PEF received approval from the FPSC authorizing PEF to recover $245 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. See "Future Liquidity and Capital Resources" and Note 7C for additional information.

INVESTING ACTIVITIES

Net cash (used) provided by investing activities for the three years ended December 31, 2007, 2006 and 2005, was $(1.457) billion, $127 million and $(1.144) billion, respectively.

Property additions at the Utilities, including nuclear fuel, were $2.199 billion and $1.546 billion in 2007 and 2006, respectively, or approximately 100 percent of consolidated capital expenditures for continuing operations in both 2007 and 2006. Capital expenditures at the Utilities are primarily for capacity expansion and normal construction activity and ongoing capital expenditures related to environmental compliance programs.

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $675 million in 2007 and $1.657 billion in 2006, cash used in investing activities increased by $602 million. The increase in 2007 was primarily due to a $539 million increase in gross property additions at the Utilities, primarily at PEF, and a $114 million increase in nuclear fuel additions, partially offset by a decrease in property additions at our diversified businesses, most of which have been discontinued or abandoned. At PEC, utility property additions primarily related to an increase in spending for compliance with the Clean Smokestacks Act. At PEF, the increase in utility property additions is primarily due to environmental compliance projects, repowering the Bartow Plant to more efficient natural gas-burning technology, which will not be completed until 2009, and nuclear and transmission projects, partially offset by lower spending on energy system distribution projects and at the Hines Unit 4 facility.

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $1.657 billion in 2006 and $475 million in 2005, cash used in investing activities decreased by $89 million in 2006 when compared with 2005. The decrease in 2006 was primarily due to a $319 million increase in net proceeds from available-for-sale securities and other investments, a $12 million decrease in nuclear fuel additions, and a $17 million decrease in other investing activities, largely offset by a $333 million increase in capital expenditures for utility property. At PEC, the increase in utility property was primarily due to environmental compliance and mobile meter reading project expenditures. At PEF, the increase in utility property was primarily due to repowering the Bartow Plant to more efficient natural gas-burning technology, which will not be completed until 2009; various distribution, transmission and steam production projects; and higher spending at the Hines Unit 4 facility, partially offset by lower spending at the Hines Unit 3 facility. The increase in utility property additions was partially offset by an $84 million decrease related to diversified businesses, which have primarily been discontinued or abandoned. Available-for-sale securities and other investments include marketable debt and equity securities and investments held in nuclear decommissioning and benefit investment trusts.

During 2007, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included approximately $615 million from the sale of PVI's CCO generation assets (See Note 3A), working capital adjustments for Gas, and the sale of poles at Progress Telecommunications Corporation.

During 2006, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included approximately $1.1 billion from the sale of Gas (See Note 3C), $405 million from the sale of DeSoto and Rowan (See Note 3D), approximately $70 million from the sale of PT LLC (See Note 3E), approximately $27 million from the sale of certain net assets of the coal mining business (See Note 3G), and approximately $16 million from the sale of Dixie Fuels (See Note 3F).

During 2005, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included $405 million in proceeds from the sale of Progress Rail in March 2005 (See Note 3H) and $42 million in proceeds from the sale of Winter Park distribution assets in June 2005 (See Notes 3K and 7C).

FINANCING ACTIVITIES

Net cash provided (used) by financing activities for the three years ended December 31, 2007, 2006 and 2005, was $195 million, $(2.468) billion and $227 million, respectively. See Note 12 for details of debt and credit facilities.

The increase in net cash provided by financing activities for 2007 compared to 2006 primarily related to the issuance of $750 million in long-term debt at PEF and the $1.7 billion reduction in holding company debt in 2006, as discussed below.

For 2006, proceeds from sales of discontinued operations and other assets, net of cash divested, were used to reduce holding company debt by $1.7 billion. The increase in cash used in financing activities for 2006 compared to 2005 was primarily related to the retirement of long-term debt in 2006, as discussed below, and a decrease in the proceeds from issuances of long-term debt.

2007

- On July 2, 2007, PEF paid at maturity $85 million of its 6.81% Medium-Term Notes with available cash on hand and commercial paper borrowings.
- On August 15, 2007, due to extreme volatility in the commercial paper market, Progress Energy borrowed $400 million under its $1.13 billion revolving credit agreement (RCA) to repay outstanding commercial paper. On October 17, 2007, Progress Energy used $200 million of commercial paper proceeds to repay a portion of the amount borrowed under the RCA. On December 17, 2007, Progress Energy used $200 million of available cash on hand to repay the remaining amount borrowed under the RCA.
- On August 15, 2007, due to extreme volatility in the commercial paper market, PEC borrowed $300 million under its $450 million RCA and paid at maturity $200 million of its 6.80% First Mortgage Bonds. On September 17, 2007, PEC used $150 million of available cash on hand to repay a portion of the amount borrowed under the RCA. On October 17, 2007, PEC repaid the remaining $150 million of its RCA loan using available cash on hand.
- On September 18, 2007, PEF issued $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. The proceeds were used to repay PEF's utility money pool borrowings and the remainder was placed in temporary investments for general corporate use as needed.
- On December 10, 2007, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity $35 million of its 6.75% Medium-Term Notes with available cash on hand.
- On December 13, 2007, PEF filed a shelf registration statement with the SEC, which became effective with the SEC on January 8, 2008. The registration statement will allow PEF to issue up to $4 billion in first mortgage bonds, debt securities and preferred stock in addition to $250 million of previously registered but unsold securities.
- Progress Energy issued approximately 3.4 million shares of common stock resulting in approximately $151 million in proceeds from its Investor Plus Stock Purchase Plan and its stock option plan. Included in these amounts were approximately 1.0 million shares for proceeds of approximately $46 million to meet the requirement of the Investor Plus Stock Purchase Plan. For 2007, the dividends paid on common stock were approximately $627 million.

2006

- On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010. These senior notes are unsecured. The net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds were used to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006, effectively terminating our $800 million 364-day credit agreement as discussed below.
- On March 31, 2006, Progress Energy, as a well-known seasoned issuer, filed a shelf registration statement with the SEC, which became effective upon filing with the SEC. Progress Energy's board of directors has authorized the issuance and sale by the Parent of up to $1.679 billion aggregate principal amount of various securities (See "Credit Facilities and Registration Statements").
- On May 3, 2006, Progress Energy restructured its existing $1.13 billion five-year RCA with a syndication of financial institutions. The new RCA is scheduled to expire on May 3, 2011, and replaced an existing $1.13 billion five-year facility, which was terminated effective May 3, 2006 (See "Credit Facilities and Registration Statements").
- On May 3, 2006, PEC's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility (See "Credit Facilities and Registration Statements").

- On May 3, 2006, PEF's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility (See "Credit Facilities and Registration Statements").
- On July 3, 2006, PEF paid at maturity $45 million of its 6.77% Medium-Term Notes, Series B with available cash on hand.
- On November 1, 2006, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity $60 million of its 7.17% Medium-Term Notes with available cash on hand.
- On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008, at a make-whole redemption price. The 6.05% Senior Notes were acquired at 100.274 percent of par, or approximately $351 million, plus accrued interest, and the 5.85% Senior Notes were acquired at 101.610 percent of par, or approximately $406 million, plus accrued interest. The redemptions were funded with available cash on hand and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions.
- On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 44.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest. The redemption was funded with available cash on hand, and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions.
- Progress Energy issued approximately 4.2 million shares of common stock resulting in approximately $185 million in proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans. Included in these amounts were approximately 1.6 million shares for proceeds of approximately $70 million to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan. For 2006, the dividends paid on common stock were approximately $607 million.

2005

- On January 31, 2005, Progress Energy entered into a new $600 million RCA, which was subsequently terminated on May 16, 2005. In March 2005, Progress Energy's $1.1 billion five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65 percent to 68 percent. In addition to the ongoing RCAs, Progress Energy entered into a new $800 million 364-day credit agreement on November 21, 2005, which was restricted for the retirement of $800 million of 6.75% Senior Notes due March 1, 2006. On March 1, 2006, the $800 million of 6.75% Senior Notes was retired, thus effectively terminating the 364-day credit agreement.
- PEC issued $300 million of First Mortgage Bonds, 5.15% Series due 2015; $200 million of First Mortgage Bonds, 5.70% Series due 2035; and $400 million of First Mortgage Bonds, 5.25% Series due 2015. PEC paid at maturity $300 million in 7.50% Senior Notes. PEC also entered into a new $450 million five-year RCA with a syndication of financial institutions, which is scheduled to expire on June 28, 2010, and filed a shelf registration statement with the SEC to provide $1.0 billion of capacity, which was declared effective on December 23, 2005. The shelf registration allows PEC to issue various securities, including First Mortgage Bonds, Senior Notes, Debt Securities and Preferred Stock.
- PEF issued $300 million in Mortgage Bonds, 4.50% Series due 2010 and $450 million in Series A Floating Rate Senior Notes due 2008. PEF paid at maturity $45 million in 6.72% Medium-Term Notes, Series B. PEF also entered into a new $450 million five-year RCA with a syndication of financial institutions, which is scheduled to expire on March 28, 2010, and filed a shelf registration statement with the SEC to provide $1.0 billion of capacity, which was declared effective on December 23, 2005. The shelf registration allows PEF to issue various securities, including First Mortgage Bonds, Debt Securities and Preferred Stock.
- Progress Energy issued approximately 4.8 million shares of our common stock for approximately $208 million in net proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans. Included in these amounts were approximately 4.6 million shares for proceeds of approximately $199 million to meet the requirements of the 401(k) and the Investor Plus Stock Purchase Plan. For 2005, the dividends paid on common stock were approximately $582 million.

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 produced substantially all of our consolidated cash from operations for the years ended December 31, 2007, 2006 and 2005. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our synthetic fuels businesses, whose operations have been reclassified to discontinued operations, have historically produced significant earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). These tax credits have 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. As of December 31, 2007, we have carried forward $830 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.

With the exception of the anticipated proceeds in 2008 from the sale of our coal mining and terminals operations (See Notes 3B and 3G), the absence of cash flow resulting from divested businesses is not expected to impact our future liquidity or capital resources as these businesses in the aggregate have been largely cash flow neutral over the last several years.

Cash from operations plus availability under our credit facilities and shelf registration statements is expected to be sufficient to meet our requirements in the near term. To the extent necessary, we may also use limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans to meet our liquidity requirements.

We issue commercial paper to meet short-term liquidity needs. In the latter half of 2007, the short-term credit markets tightened, resulting in higher interest rate spreads and shorter durations. Currently, the market has improved; however, there has been volatility on commercial paper spreads, as the supply of short-term commercial paper has increased following recent actions by the Federal Open Market Committee. 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 from our RCAs, issuing short-term floating rate notes, and/or issuing long-term debt.

Progress Energy has approximately $9.7 billion in outstanding debt. Only $860 million of our debt is insured. These bonds are obligations of the Utilities and are traded in the tax-exempt auction rate securities market. Ambac Assurance Corporation insures approximately $620 million of the bonds and XL Capital Assurance, Inc. insures the remaining $240 million. To date, auctions for the Utilities' bonds have seen an increase in the interest rates that are periodically reset at each auction. Since the downgrade of XL Capital Assurance, Inc. on February 7, 2008, by Moody's Investors Service, Inc. (Moody's), we have seen additional market volatility and an increase in the reset interest rates for a portion of our tax-exempt bonds. If additional downgrades by Moody's or Standard & Poor's Rating Services (S&P) occur, we could see additional volatility in this market and the potential for higher rate resets. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

Over the long term, meeting the anticipated load growth at the Utilities will require a balanced approach, including energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities, potentially including new baseload generation facilities in both Florida and the Carolinas toward the end of the next decade. This approach will require the Utilities to make significant capital investments. See "Introduction – Strategy" for additional information. These anticipated capital investments are expected to be funded through a combination of cash from operations and issuance of long-term debt, preferred stock and common equity, which are dependent on our ability to successfully access capital markets. 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.

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

At December 31, 2007, the current portion of our long-term debt was $877 million, which we expect to fund with a combination of cash from operations, proceeds from sales of assets, commercial paper borrowings and long-term debt. See Note 3 for additional information on asset sales.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, as discussed in "Other Matters – Regulatory Environment" and Note 7, and filings for 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.

PEC Base Rates

PEC's base rates are subject to the regulatory jurisdiction of the North Carolina Utilities Commission (NCUC) and the South Carolina Public Service Commission (SCPSC). As further discussed in Note 21B, the Clean Smokestacks Act was enacted in 2002. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended December 31, 2007, unless there were extraordinary events beyond the control of the utilities or unless the utilities persistently earned a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. There were no adjustments to PEC's base rates during the five-year period ended December 31, 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation.

On March 23, 2007, PEC filed a petition with the NCUC requesting that it be allowed to amortize the remaining 30 percent (or $244 million) of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, with discretion to amortize up to $174 million in either year. Additionally, among other things, PEC requested that the NCUC allow PEC to include in its rate base those eligible compliance costs exceeding the original estimated compliance costs and that PEC be allowed to accrue AFUDC on all eligible compliance costs in excess of the original estimated compliance costs. PEC also requested that any prudency review of PEC's environmental compliance costs be deferred until PEC's next ratemaking proceeding in which PEC seeks to adjust its base rates. On October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, the Carolina Utility Customers Associations (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis, with the NCUC indicating that it intended to initiate a review in 2009 to consider all reasonable alternatives and proposals related to PEC's recovery of its Clean Smokestacks Act compliance costs in excess of the original estimated costs of $813 million. Additionally, the NCUC ordered that no portion of Clean Smokestacks Act compliance costs directly assigned, allocated or otherwise attributable to another jurisdiction shall be recovered from PEC's retail North Carolina customers, even if recovery of these costs is disallowed or denied, in whole or in part, in another jurisdiction. We cannot predict the outcome of PEC's recovery of eligible compliance costs exceeding the original estimated compliance costs.

PEC Pass-through Clause Cost Recovery

On May 2, 2007, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers. On June 27, 2007, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceedings. The settlement agreement resolved all issues and provided for a $12 million increase in fuel rates. Effective July 1, 2007, residential electric bills increased by $1.83 per 1,000 kWh, or 1.9 percent, for fuel cost recovery. At December 31, 2007, PEC's South Carolina deferred fuel balance was $21 million.

On June 8, 2007, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. PEC asked the NCUC to approve a $48 million increase in fuel rates. On September 25, 2007, the NCUC approved PEC's petition. The increase took effect October 1, 2007, and increased residential electric bills by $1.30 per 1,000 kWh, or 1.3 percent, for fuel cost recovery. This was the second increase associated with a three-year settlement approved by the NCUC in 2006. The settlement provided for an increase of $177 million effective October 1, 2006; $48 million effective October 1, 2007, as discussed above; and an additional increase of approximately $30 million in October 2008. On November 21, 2006, CUCA filed an appeal with the North Carolina Tenth District Court of Appeals of the NCUC's order approving the settlement on the grounds that the NCUC did not have the statutory authority to establish fuel rates for more than one year. On October 24, 2007, CUCA filed a motion to withdraw their appeal. On November 7, 2007, the North Carolina Tenth District Court of Appeals granted CUCA's motion. At December 31, 2007, PEC's North Carolina deferred fuel balance was $241 million, of which $114 million is expected to be collected after 2008 and has been classified as a long-term regulatory asset.

As discussed further in "Other Matters – Regulatory Environment," South Carolina and North Carolina state energy legislation that became law in 2007 may impact our liquidity over the long term. Among other provisions, these state energy laws provide mechanisms for recovery of certain baseload generation construction costs and expand annual fuel clause mechanisms so that additional costs may be recovered annually.

Comprehensive energy legislation enacted in 2007 in North Carolina expanded the costs that may be recovered annually under the fuel clause, including costs of reagents used in emissions control technologies (commodities such as ammonia and limestone), the avoided costs associated with renewable energy purchases and certain components of purchased power not previously recoverable through the fuel clause. Energy legislation enacted in 2007 in South Carolina expanded the annual fuel clause mechanism to include recovery of the costs of reagents used in the operation of emissions control technologies. We anticipate PEC's reagent and purchased power costs eligible for jurisdictional recovery under the North Carolina and South Carolina energy laws will total approximately $50 million in 2008.

The North Carolina law mandates minimum Renewable Energy and Energy Efficiency Portfolio Standards (REPS) beginning in 2012. Utilities are allowed to recover the premium to be paid to comply with the requirements above the cost they would have otherwise incurred to meet consumer demand. The annual amount that can be recovered through the REPS clause is capped and once a utility has expended monies equal to the cap, the utility is deemed to have met its obligation under the REPS, regardless of the actual renewables generated or purchased. The recovery cap requirement begins in 2008 and, as a result, PEC will begin deferring certain costs associated with renewable energy purchases in 2008. These costs are expected to be immaterial in 2008.

In addition, the North Carolina law also allows PEC to recover the costs of new DSM and energy-efficiency programs through an annual DSM clause. DSM programs include any program or initiative that shifts the timing of electricity use from peak to nonpeak periods. PEC has begun implementing a series of DSM and energy-efficiency programs and for the year ended December 31, 2007, deferred $2 million of implementation and program costs for future recovery.

See "Other Matters – Regulatory Environment" for additional information about state and federal legislation.

PEF Base Rates

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009, with PEF having sole option to extend the agreement through the last billing cycle of June 2010. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006 whereby PEF will refund two-thirds of retail base revenues between a specified threshold and specified cap, which will be adjusted annually, and 100 percent of revenues above the specified cap. PEF's retail base revenues did not exceed the specified 2007 or 2006 thresholds, and thus no revenues were subject to revenue sharing. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the recovery of post-9/11 security costs through the capacity clause and the carrying costs of coal inventory in transit and coal procurement costs through the fuel clause. If PEF's regulatory return on equity (ROE) falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

On October 23, 2007, the FPSC approved a stipulation and settlement agreement that settled all issues related to recovery of the revenue requirements of Hines Unit 2 and Hines Unit 4 and provided that PEF shall 1) increase its base rates for the revenue requirements of Hines Unit 2 and Hines Unit 4 and 2) simplify the implementation of the base rate increase of $89 million by making it effective with the first billing cycle in January 2008. The revenue requirements of Hines Unit 2 were previously being recovered through the fuel clause.

PEF Pass-through Clause Cost Recovery

On September 4, 2007, PEF filed a request with the FPSC seeking approval of a cost adjustment to reflect a projected over-collection of fuel costs in 2007, declining projected fuel costs for 2008, and other recovery clause factors. PEF asked the FPSC to approve a $163 million, or 4.53 percent, decrease in rates effective January 1, 2008. This cost adjustment would decrease residential bills by $5.00 for the first 1,000 kWh. As discussed above, residential base rates increased effective January 1, 2008, by $2.73 for the first 1,000 kWh. After considering the net effect of the base rate increase and the proposed fuel cost adjustment, 2008 residential bills would decrease by a net amount of $2.27 for the first 1,000 kWh. The FPSC approved the cost-recovery rates for 2008 in an order dated January 8, 2008. At December 31, 2007, PEF was over-recovered in fuel and capacity costs by $140 million, over-recovered in conservation costs by $14 million, over-recovered in environmental compliance by $5 million and had accrued disallowed fuel costs of $14 million as discussed below.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and sulfur dioxide (SO_2) allowance costs associated with PEF's purported failure to utilize the most economical sources of coal at Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. On July 31, 2007, the FPSC heard this matter. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the 4-1 majority found that PEF had not been prudent in purchasing a portion of its coal requirements during the period from 2003 to 2005. Accordingly, the FPSC ordered PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. On October 25, 2007, the OPC requested the FPSC to reconsider its October 10, 2007 order asserting that the FPSC erred in not ordering a larger refund. PEF filed its opposition to the OPC's request on November 1, 2007. On February 12, 2008, the FPSC denied the OPC's request for reconsideration. PEF is also evaluating its options, including an appeal to the Florida Supreme Court of the FPSC's October 10, 2007 order. We cannot predict the outcome of this matter. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. On October 4, 2007, PEF filed a motion to establish a separate docket on the prudence of its coal purchases for CR4 and CR5 for the years 2006 and 2007. On October 17, 2007, the FPSC granted that motion. The OPC filed testimony in support of its position to require PEF to refund at least $14 million for alleged excessive fuel recovery charges for 2006 coal purchases. PEF believes its coal procurement practices were prudent. We cannot predict the outcome of this matter.

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate Crystal River Unit No. 3 Nuclear Plant (CR3), bid rule exemption and recovery of the revenue requirements of the uprate through PEF's fuel recovery clause. To the extent the expenditures are prudently incurred, PEF's investment in the CR3 uprate is eligible for recovery through base rates. PEF's petition would allow for more prompt recovery. On February 8, 2007, the FPSC issued an order approving PEF's request for a need determination to uprate through a multi-stage uprate to be completed by 2012. PEF's need determination filing included estimated project costs of approximately $382 million. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. On March 27, 2007, the FPSC denied the motion to abate and directed the staff of the FPSC to conduct a hearing on the matter to determine whether the revenue requirements of the uprate should be recovered through the fuel recovery clause. On May 4, 2007, PEF filed amended testimony clarifying the scope of the project. The FPSC held a hearing on this matter on August 7 and 8, 2007. The staff of the FPSC recommended that PEF be allowed to recover prudent and reasonable costs of Phase 1, instrumentation modifications for improved accuracy, estimated at $6 million through the fuel clause. The staff of the FPSC recommended that the costs of all other phases, estimated at $376 million, be considered in a base rate proceeding. On October 19, 2007, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. On November 21, 2007, PEF filed a petition with the FPSC seeking cost recovery under Florida's comprehensive energy bill enacted in 2006, and the FPSC's new nuclear cost-recovery rule. On February 13, 2008, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. PEF will proceed with cost recovery under Florida's comprehensive energy bill and the FPSC's nuclear cost-recovery rule based on the regulatory precedence established by a FPSC order to an unaffiliated Florida utility for a nuclear uprate project. We cannot predict the outcome of this matter.

PEF has received approval from the FPSC for recovery of costs associated with the remediation of distribution and substation transformers through the ECRC, which were estimated to be $31 million at December 31, 2007. Additionally, on November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR through the ECRC (see "Other Matters – Environmental Matters" for discussion regarding CAMR). The FPSC also approved cost recovery of prudently incurred costs necessary to achieve this strategy, which are currently estimated to be $1.3 billion to $2.3 billion.

Storm Cost Recovery

On August 29, 2006, the FPSC approved a settlement agreement related to PEF's storm cost-recovery docket that allowed PEF to extend its then-current two-year storm surcharge. The requested 12-month extension, which began in August 2007, will replenish the existing storm reserve by an estimated $126 million. In the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. Intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence.

Nuclear Cost Recovery

The FPSC approved new rules on February 13, 2007, that allow PEF to recover prudently incurred siting, preconstruction costs and AFUDC on an annual basis through the capacity cost-recovery clause. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned once 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. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. 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.

Other Regulatory Matters

Additionally, on July 13, 2007, the governor of Florida issued executive orders to address reduction of greenhouse gas emissions. The FPSC has held meetings regarding the renewable portfolio standard but no actions have been taken or rules issued. The Energy and Climate Action Team appointed by the governor submitted its initial recommendations for implementation of the governor's executive orders on November 1, 2007. The recommendations encourage the development and implementation of energy-efficiency and conservation measures, implementation of a climate registry, and consideration of a cap-and-trade approach to reducing the state's greenhouse gas emissions. Additional development and discussion of the recommendations will occur through a stakeholder process in 2008. The Florida Department of Environmental Protection held its first rulemaking workshop on the greenhouse gas emissions cap on August 22, 2007, and a second workshop on December 5, 2007. We anticipate drafts of the rule will be issued in 2008. We cannot currently predict the costs of complying with the laws and regulations that may ultimately result from these executive orders. Our balanced solution, as described in "Increasing Energy Demand," includes greater investment in energy efficiency, renewable energy and state-of-the-art generation and demonstrates our commitment to environmental responsibility. In addition, the Florida Energy Commission, which was established by the Legislature in 2006, published its energy policy and climate change recommendations on December 31, 2007. The report includes proposed legislative language that would implement energy-efficiency and conservation programs, participation in the multi-state Climate Registry, and emissions reduction targets that are similar to those contained in the governor's executive orders. We cannot currently predict the impacts to our liquidity of complying with these executive orders and the Florida Energy Commission's recommendations.

EPACT, among other provisions, gave the FERC accountability for system reliability and the authority to impose civil penalties. On June 18, 2007, compliance with 83 FERC-approved reliability standards became mandatory for all registered users, owners and operators of the bulk power system, including PEC and PEF. On December 20, 2007, the FERC approved three additional planning and operating reliability standards. Additionally, on January 17, 2008, the FERC approved eight mandatory critical infrastructure protection reliability standards to protect the bulk power system against potential disruptions from cyber security breaches.

Based on FERC's directive to revise 56 of the adopted standards, we expect standards to migrate to more definitive and enforceable requirements over time. We are committed to meeting those standards. The financial impact of mandatory compliance cannot currently be determined. Failure to comply with the reliability standards could result in the imposition of fines and civil penalties. If we are unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on our cash flows.

CAPITAL EXPENDITURES

Total cash from operations and proceeds from long-term debt 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 2007.

As shown in the table below, 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 internally generated funds, long-term debt, preferred stock and/or common equity. In addition, we have $2.030 billion in credit facilities that support the issuance of commercial paper. Access to the commercial paper market provides additional liquidity to help meet working capital requirements. We anticipate our regulated capital expenditures will increase in 2008 and 2009, primarily due to increased spending on environmental initiatives and current growth and maintenance projects. AFUDC – borrowed funds represents the debt costs of capital funds necessary to finance the construction of new regulated plant assets.

	Actual	Forecasted		
(in millions)	**2007**	2008	2009	2010
Regulated capital expenditures	**$1,874**	$2,420	$2,080	$1,670
Nuclear fuel expenditures	**228**	260	290	270
AFUDC – borrowed funds	**(16)**	(40)	(50)	(40)
Other capital expenditures	**10**	20	20	20
Total before potential nuclear construction	**2,096**	2,660	2,340	1,920
Potential nuclear construction[a]	**94**	160	520	850
Total	**$2,190**	$2,820	$2,860	$2,770

[a] Expenditures for potential nuclear construction are net of AFUDC – borrowed funds and include land, development, licensing, equipment and associated transmission. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build; final contract negotiations; timing and escalation of project costs; and the percentages, if any, of joint ownership. These expenditures, which are primarily at PEF, are subject to cost-recovery provisions in the Utilities' respective jurisdictions (see discussion under "Other Matters – Nuclear").

Regulated capital expenditures for 2008, 2009 and 2010 in the table above include approximately $730 million, $350 million and $130 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2008, 2009 and 2010 include $180 million, $70 million and $80 million, respectively, at PEC and $550 million, $280 million and $50 million, respectively, at PEF. We currently estimate that total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or cost-recovery clauses, could be in excess of $700 million at PEC and in excess of $1.9 billion at PEF through 2018, which is the latest compliance target date for current air and water quality regulations. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance costs and related recovery of costs.

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

The following table summarizes our RCAs and available capacity at December 31, 2007:

(in millions)	Total	Outstanding	Reserved[a]	Available
Progress Energy, Inc.				
Five-year (expiring 5/3/11)	$1,130	$–	$220	$910
PEC				
Five-year (expiring 6/28/10)	450	–	–	450
PEF				
Five-year (expiring 3/28/10)	450	–	–	450
Total credit facilities	$2,030	$–	$220	$1,810

[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, 2007, Progress Energy, Inc. had a total amount of $19 million of letters of credit issued, which were supported by the RCA.

All of the revolving credit facilities supporting the credit were arranged through a syndication of financial institutions. There are no bilateral contracts associated with these facilities. See Note 12 for additional discussion of our credit facilities.

The RCAs provide liquidity support for issuances of commercial paper and other short-term obligations. We expect to continue to use commercial paper issuances as a source of liquidity as long as we maintain our current short-term ratings. Fees and interest rates under Progress Energy's RCA are based upon the credit rating of Progress Energy's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2 by Moody's and BBB by S&P. Fees and interest rates under PEC's RCA are based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB by S&P. Fees and interest rates under PEF's RCA are based upon the credit rating of PEF's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB by S&P.

All of the credit facilities include a defined maximum total debt-to-total capital ratio (leverage). We are currently in compliance with these covenants and were in compliance with these covenants at December 31, 2007. See Note 12 for a discussion of the credit facilities' financial covenants. At December 31, 2007, the calculated ratios, pursuant to the terms of the agreements, are as disclosed in Note 12.

Progress Energy, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which Progress Energy may issue an indeterminate 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. The board of directors has authorized the issuance and sale of up to $1.0 billion aggregate principal amount of various securities off the new shelf registration statement, in addition to $679 million of various securities, which were not sold from our prior shelf registration statement. Accordingly, at December 31, 2007, Progress Energy has the authority to issue and sell up to $1.679 billion aggregate principal amount of various securities.

PEC has on file with the SEC a shelf registration statement under which it can issue up to $1.0 billion of various long-term debt securities and preferred stock.

PEF has on file with the SEC a shelf registration statement under which it can issue up to $4.250 billion of various long-term debt securities and preferred stock.

Both PEC and PEF can issue First Mortgage Bonds under their respective First Mortgage Bond indentures. At December 31, 2007, PEC and PEF could issue up to $3.657 billion and $2.408 billion, respectively, based on property additions and $1.827 billion and $175 million, respectively, based upon retirements of previously issued first mortgage bonds.

CAPITALIZATION RATIOS

The following table shows our total debt to total capitalization ratios at December 31:

	2007	2006
Common stock equity	**45.7%**	47.2%
Preferred stock and minority interest	**1.0%**	0.6%
Total debt	**53.3%**	52.2%

CREDIT RATING MATTERS

The major credit rating agencies have currently rated our securities as follows:

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Progress Energy, Inc.			
Outlook	Stable	Stable	Stable
Corporate credit rating	n/a	BBB+	BBB
Senior unsecured debt	Baa2	BBB	BBB
Commercial paper	P-2	A-2	F-2
PEC			
Outlook	Stable	Stable	Stable
Corporate credit rating	A3	BBB+	A-
Commercial paper	P-2	A-2	F-1
Senior secured debt	A2	A-	A+
Senior unsecured debt	A3	BBB	A
Subordinate debt	Baa1	n/a	n/a
Preferred stock	Baa2	BBB-	A-
PEF			
Outlook	Stable	Stable	Stable
Corporate credit rating	A3	BBB+	A-
Commercial paper	P-2	A-2	F-1
Senior secured debt	A2	A-	A+
Senior unsecured debt	A3	BBB	A
Preferred stock	Baa2	BBB-	A-
FPC Capital I			
Quarterly Income Preferred Securities[a]	Baa2	BBB-	n/a
Progress Capital Holdings, Inc.			
Senior unsecured debt[b]	Baa1	BBB-	n/a

(a) Guaranteed by Progress Energy, Inc. and Florida Progress.
(b) Guaranteed by Florida Progress.

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

On September 6, 2007, S&P upgraded the first mortgage bonds of both PEC and PEF to A- from BBB+ as a result of a methodology change for collateral coverage requirements. Because both PEC and PEF had asset to potential secured debt ratios of less than 1.5, they were assigned a recovery rating of 1, which qualified for a one-notch increase over their corporate credit ratings.

On July 13, 2007, Fitch Ratings upgraded the long-term ratings of both PEC and PEF to A- from BBB+ and revised their rating outlooks to stable from positive. Fitch Ratings cited cash flow coverage and leverage credit ratios more consistent with the A rating category at the Utilities, sound utility operations and operations in historically favorable regulatory environments as the primary factors for the upgrades. Fitch Ratings also noted lowered group linkage risks for PEC and PEF resulting from improved business risk at the Parent due to the sale or wind-down of non-utility operations and reduced debt.

On June 15, 2007, Moody's upgraded the corporate credit rating for PEC to A3 from Baa1 and revised its outlook to stable from positive. Moody's cited strong cash flow coverage measures and financial metrics, operations in constructive regulatory environments with growing service territories and lower debt and business risk at the Parent as the primary factors in the upgrade.

On March 15, 2007, S&P upgraded corporate credit ratings to BBB+ from BBB at Progress Energy, Inc., PEC and PEF and revised each company's outlook to stable from positive. S&P cited the significant reduction in our holding company debt and the moderation of business risk achieved by our renewed focus on our regulated utilities as the primary factors in the upgrade.

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 that are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." 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, 2007, we have issued $481 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, 2007, 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. Amounts in the following table are estimated based upon contractual terms, and actual amounts will likely differ from amounts presented below. 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, 2007, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt[a] (See Note 12)	$9,668	$877	$806	$1,950	$6,035
Interest payments on long-term debt[b]	6,865	558	1,003	816	4,488
Capital lease obligations (See Note 22B)	657	28	57	63	509
Operating leases (See Note 22B)	740	62	66	58	554
Fuel and purchased power[c] (See Note 22A)	17,644	2,473	3,778	2,534	8,859
Other purchase obligations[d] (See Note 22A)	1,228	808	324	32	64
Minimum pension funding requirements[e]	193	34	105	54	–
Uncertain tax positions[f] (See Note 14)	–	–	–	–	–
Other commitments[g]	133	13	27	27	66
Total	$37,128	$4,853	$6,166	$5,534	$20,575

[a] Our maturing debt obligations are generally expected to be repaid with asset sales and 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, 2007.
[c] Fuel and purchased power commitments represent the majority of our remaining future commitments after debt obligations. Essentially all of our fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.
[d] We have additional contractual obligations associated with our discontinued CCO operations, which are not reflected in this table. These obligations include other purchase obligations of $3 million each for 2008 and 2009.
[e] Projected pension funding status is based on current actuarial estimates and is subject to future revision.
[f] Uncertain tax positions of $93 million are not reflected in this table as we cannot predict when open income tax years will be closed with completed examinations. We are not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2008.
[g] In 2008, PEC must begin transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

OTHER MATTERS

Synthetic Fuels Tax Credits

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Code (Section 29). The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied, including a requirement that the synthetic fuels differ significantly in chemical composition from the coal used to produce such synthetic fuels and that the fuel was produced from a facility that was placed in service before July 1, 1998. 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 tax credits associated with synthetic fuels in a particular year were phased out if annual average market prices for crude oil exceeded certain prices. Synthetic fuels were generally not economical to produce and sell absent the credits. The synthetic fuels tax credit program expired at the end of 2007.

TAX CREDITS

Legislation enacted in 2005 redesignated the Section 29 tax credit as a general business credit under Section 45K of the Code (Section 45K) effective January 1, 2006. The previous amount of Section 29 tax credits that we were allowed to claim in any calendar year through December 31, 2005, was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits. The redesignation of Section 29 tax credits as a Section 45K general business credit removes the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a 20-year carry forward period. This provision allowed us to produce more synthetic fuels than we have historically produced, should we have chosen to do so.

Total Section 29/45K credits generated through December 31, 2007 (including those generated by Florida Progress prior to our acquisition), were approximately $2.028 billion, of which $1.054 billion has been used to offset regular federal income tax liability, $830 million is being carried forward as deferred tax credits and $144 million has been reserved due to the estimated phase-out of tax credits due to high oil prices, as described below.

IMPACT OF CRUDE OIL PRICES

Section 29 provided that if the Annual Average Price exceeded the Threshold Price, the amount of Section 29/45K tax credits was reduced for that year. Also, if the Annual Average Price exceeded the Phase-out Price, the Section 29/45K tax credits were eliminated for that year. The Threshold Price and the Phase-out Price were adjusted annually for inflation.

If the Annual Average Price fell between the Threshold Price and the Phase-out Price for a year, the amount by which Section 29/45K tax credits were reduced depended on where the Annual Average Price fell in that continuum. The Department of the Treasury calculates the Annual Average Price based on the Domestic Crude Oil First Purchases Prices published by the Energy Information Agency (EIA). Because the EIA publishes its information on a three-month lag, the secretary of the Treasury finalizes the calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2006 was published on April 4, 2007. Based on the Annual Average Price for calendar year 2006 of $59.68, our synthetic fuels tax credits generated during 2006 were reduced by 33 percent, or approximately $35 million. The Annual Average Price for calendar year 2007 is expected to be published in early April 2008.

On September 14, 2007, we idled production of synthetic fuels at our majority-owned synthetic fuels facilities. As discussed below, the decision to idle production was based on the high level of oil prices, and the resumption of synthetic fuels production was dependent upon a number of factors, including a reduction in oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007, and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. The operation of synthetic fuels facilities on behalf of third parties continued through late 2007. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased in late December 2007, we reclassified the operations of our synthetic fuels businesses as discontinued operations in the fourth quarter of 2007.

We estimate that the 2007 Threshold Price will be approximately $57 per barrel and the Phase-out Price will be approximately $71 per barrel, based on an estimated inflation adjustment for 2007. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $5 lower than the corresponding daily New York Mercantile Exchange (NYMEX) prompt month settlement price for light sweet crude oil. Through December 31, 2007, the average NYMEX settlement price for light sweet crude oil was $72.35 per barrel. Based upon the estimated 2007 Threshold Price and Phase-out Price and assuming that the $5 average differential between the Domestic Crude Oil First Purchases Price published by the EIA and the NYMEX settlement price continued through December 31, 2007, we estimate that the synthetic fuels tax credit amount for 2007 will be reduced by approximately 70 percent. Therefore, we reserved 70 percent or approximately $144 million of the $205 million of tax credits generated during 2007. The final calculations of any reductions in the value of the tax credits will not be determined until April 2008 when final 2007 oil prices are published.

In January 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a NYMEX basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production and was marked-to-market with changes in fair value recorded through earnings. The derivative contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact on 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo Synfuel LLC (Ceredo). As discussed below in "Sales of Partnership Interests" and in Notes 1C and 3J, we disposed of our 100 percent ownership interest in Ceredo in March 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts, including $57 million attributable to Ceredo, of which $42 million was attributed to minority interest for the portion of the gain subsequent to disposal. See Note 17A and "Quantitative and Qualitative Disclosures About Market Risk" and for a discussion of market risk and derivatives.

IMPAIRMENT OF SYNTHETIC FUELS AND OTHER RELATED LONG-LIVED ASSETS

We monitor our long-lived assets for impairment as warranted. With the idling of our synthetic fuels facilities during the second quarter of 2006 due to the high level of oil prices, we performed an impairment evaluation of our synthetic fuels and other related operating long-lived assets. The impairment test considered numerous factors, including, among other things, continued high oil prices and the then-current "idle" state of our synthetic fuels facilities. Based on the results of the impairment test, we recorded pre-tax impairment charges of $91 million ($55 million after-tax) during the quarter ended June 30, 2006 (See Notes 8 and 9). These charges represent the entirety of the asset carrying value of our synthetic fuels intangible assets and manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities are located. As discussed in Note 3B, these charges have been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income.

SALES OF PARTNERSHIP INTERESTS

In March 2007, we disposed of, through our subsidiary Progress Fuels, our 100 percent ownership interest in Ceredo, a subsidiary that produces and sells qualifying coal-based solid synthetic fuels, to a third-party buyer. In addition, we entered into an agreement to operate the Ceredo facility on behalf of the buyer. At closing, we received cash proceeds of $10 million and a nonrecourse note receivable of $54 million. Payments on the note are due as we produce and sell qualifying coal-based solid synthetic fuels on behalf of the buyer. During 2007, we produced 2.7 million tons. In accordance with the terms of the agreement, we received payments on the note related to 2007 production of $49 million in 2007 and $5 million subsequent to year-end. The total amount of proceeds is subject to adjustment once the final value of the 2007 Section 29/45K credits is known. Pursuant to the terms of the disposal agreement, the buyer had the right to unwind the transaction if an Internal Revenue Service (IRS) reconfirmation private letter ruling was not received by November 9, 2007, or if certain adverse changes in tax law, as defined in the agreement, occurred before November 19, 2007. The IRS reconfirmation private letter ruling was received on October 29, 2007, and no adverse change in tax law occurred prior to November 19, 2007. As of December 31, 2007, due to indemnification provisions, we recorded losses on disposal of $3 million based on the estimated value of the 2007 Section 29/45K tax credits. The operations of Ceredo have been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. Subsequent to the disposal, we remained the primary beneficiary of Ceredo and continued to consolidate Ceredo in accordance with FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" (FIN 46R), but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there was no net earnings impact from Ceredo's operations. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer, which increases the loss on disposal or reduces any potential deferred gain. The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods (See Note 3J and Note 22C).

In June 2004, through our subsidiary Progress Fuels, we sold in two transactions a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of our synthetic fuels facilities. The transactions were structured such that proceeds from the sales would be received over time, which was typical of such sales in the industry. Gains from the sales are recognized on a cost-recovery basis. Gain recognition is dependent on the synthetic fuels production qualifying for Section 29/45K tax credits and the value of such tax credits, as discussed above. Until the gain recognition criteria are met, gains from selling interests in Colona were deferred. Due to the impact on production from the 2007 idling of the synthetic fuels facilities as discussed above and pursuant to the terms of the sales agreements, in January 2008, the purchasers abandoned their interests in Colona. We recognized a $4 million gain and $30 million gain on these transactions in the years ended December 31, 2006 and 2005, respectively, which have been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income (See Note 3L). In 2007, due to the increase in the price of oil that limits synthetic fuels tax credits, we did not record any additional gain.

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

Regulatory Environment

The Utilities' operations in North Carolina, South Carolina and Florida are regulated by the NCUC, SCPSC and the FPSC, respectively. The Utilities are also subject to regulation by the FERC, the Nuclear Regulatory Commission (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 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 when, or if, any of these states will move to increase retail competition in the electric industry.

The retail rate matters affected by state regulatory authorities are discussed in detail 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 December 19, 2007, the president signed into law the federal Energy Independence and Security Act of 2007. The legislation strengthened Corporate Average Fuel Economy standards for automotive manufacturers' fleets of passenger cars and light trucks and significantly increased the amount of ethanol required to be used as a gasoline additive. The legislation also provided incentives for the development of plug-in hybrid electric vehicles and created new energy-efficiency standards in commercial, residential and governmental use. In addition, the legislation authorized increased funding for research into the use of carbon capture and storage technology, and directs states to consider "smart grid" improvements to transmission infrastructure. The law did not contain any provisions for a federal Renewable Portfolio Standard.

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. The law mandates minimum REPS for the use of energy from specified renewable energy resources or implementation of energy-efficiency measures by the state's electric utilities beginning with a 3 percent requirement in 2012 and increasing to 12.5 percent in 2021 for regulated public utilities, including PEC. The premium to be paid by electric utilities to comply with the requirements, above the cost they would have otherwise incurred to meet consumer demand, is to be recovered through an annual clause. The annual amount that can be recovered through the REPS clause is capped and once a utility has expended monies equal to the cap, the utility is deemed to have met its obligations under the REPS, regardless of the actual renewables generated or purchased. The law grants the NCUC authority to modify or alter the REPS requirements if the NCUC determines it is in the public interest to do so. The recovery cap requirement begins in 2008 and, as a result, PEC will begin deferring certain costs associated with renewable energy purchases in 2008. These costs are expected to be immaterial in 2008.

The law allows the utility to meet a portion of the REPS with energy reductions achieved through energy-efficiency programs. Energy-efficiency programs include any program or activity implemented after January 1, 2007, that results in less energy being used to perform the same function. Through the year 2020, a utility can use energy-efficiency programs to satisfy up to 25 percent of their REPS; beginning in 2021, these programs may constitute up to 40 percent of the requirements.

The law allows the utility to recover the costs of new DSM and energy-efficiency programs through an annual DSM clause. The law allows the utility to capitalize those costs that are intended to produce future benefits and authorizes the NCUC to approve other forms of financial incentives to the utility for DSM and energy-efficiency programs. DSM programs include any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control and interruptible load. PEC has begun implementing a series of DSM and energy-efficiency programs and deferred $2 million of implementation and program costs for future recovery for the year ended December 31, 2007.

The law also expands the definition of the traditional fuel clause so that additional costs may be recovered annually. These additional costs include costs of reagents (commodities such as ammonia and limestone used in emissions control technologies), the avoided costs associated with renewable energy purchases and certain components of purchased power not previously recoverable through the fuel clause (see additional discussion below). The North Carolina law also authorizes the NCUC to allow annual prudence reviews of the construction costs of a baseload generating plant if requested by the public utility that is constructing the plant and removes the requirement that a public utility prove financial distress before it may include construction work in progress in rate base and adjust rates, accordingly, in a general rate case while a baseload generating plant is under construction.

On October 26, 2007, the NCUC issued its proposed rules for implementation of the law. PEC expects final rules to be issued by the end of the first quarter of 2008. Until the rulemaking process is completed, we cannot predict the costs of complying with the law. PEC would be able to annually recover its reasonable prudent compliance costs.

During 2007, the South Carolina legislature ratified new energy legislation, which became law on May 3, 2007. Key elements of the law include expansion of the annual fuel clause mechanism to include recovery of the costs of reagents used in the operation of PEC's emissions control technologies (see additional discussion below). The law also includes provisions to provide base rate cost recovery for upfront development costs associated with nuclear baseload generation and construction costs associated with nuclear or coal baseload generation without a base rate proceeding and the ability to recover financing costs for new nuclear baseload generation through annual clauses.

On November 30, 2007, PEC filed a petition with the SCPSC seeking authorization to create a deferred account for DSM and energy-efficiency program expenses pending the filing of application requesting a DSM and energy-efficiency program expense clause to recover such program costs. On December 12, 2007, the SCPSC granted PEC's petition. As a result, through December 31, 2007, PEC deferred an immaterial amount of implementation and program costs for future recovery in the South Carolina jurisdiction.

On July 13, 2007, the governor of Florida issued executive orders to address reduction of greenhouse gas emissions. The executive orders call for the first southeastern state cap-and-trade program and include adoption of a maximum allowable emissions level of greenhouse gases for Florida utilities. The standard 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.

Among other things, the executive orders also requested that the FPSC initiate a rulemaking by September 1, 2007, 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 on-site 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). The FPSC has held meetings regarding the renewable portfolio standard but no actions have been taken or rules issued. The Energy and Climate Action Team appointed by the governor submitted its initial recommendations for implementation of the governor's executive orders on November 1, 2007. The recommendations encourage the development and implementation of energy-efficiency and conservation measures, implementation of a climate registry and consideration of a cap-and-trade approach to reducing the state's greenhouse gas emissions. Additional development and discussion of the recommendations will occur through a stakeholder process in 2008. The Florida Department of Environmental Protection held its first rulemaking workshop on the greenhouse gas emissions cap on August 22, 2007, and a second workshop on December 5, 2007. We anticipate drafts of the rule will be issued in 2008. In addition, the Florida Energy Commission, which was established by the Legislature in 2006, published its energy policy and climate change recommendations on December 31, 2007. The report includes proposed legislative language that would implement energy-efficiency and conservation programs, participation in the multi-state Climate Registry and emissions reduction targets that are similar to those contained in the governor's executive orders.

We cannot currently predict the costs of complying with the laws and regulations that may ultimately result from these executive orders and the Florida Energy Commission's recommendations. Our balanced solution, as described in "Increasing Energy Demand," includes greater investment in energy efficiency, renewable energy and state-of-the-art generation and demonstrates our commitment to environmental responsibility.

On April 10, 2007, the FPSC adopted a rule that specifies what storm costs will be recoverable and whether such recoverable costs would be offset against a utility's storm reserve fund or recoverable through its base rates. PEF does not believe that compliance with this rule will materially increase its costs.

EPACT, among other provisions, gave the FERC accountability for system reliability and the authority to impose civil penalties. EPACT provides procedures and rules for the establishment of an electric reliability organization (ERO) that will propose and enforce mandatory reliability standards. On July 20, 2006, the FERC certified the North American Electric Reliability Corporation (NERC) as the ERO. Included in this certification was a provision for the ERO to delegate authority for the purpose of proposing and enforcing reliability standards in particular regions of the country by entering into delegation agreements with regional entities. The SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC) are the regional entities for PEC and PEF, respectively.

As discussed in "Future Liquidity and Capital Resources – Other Regulatory Matters," during 2007 and 2008, the FERC approved a significant number of reliability standards developed by the NERC and set aside other standards pending further development. Compliance with FERC-approved reliability standards is mandatory for all registered users, owners and operators of the bulk power system, including PEC and PEF. Prior to the FERC action, electric utility industry compliance with the NERC standards had been voluntary.

Based on FERC's directive to revise 56 of the adopted standards, we expect standards to migrate to more definitive and enforceable requirements over time. We are committed to meeting those standards. The financial impact of mandatory compliance cannot currently be determined. Failure to comply with the reliability standards could result in the imposition of fines and civil penalties. If we are unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Prior to the effective date of mandatory compliance with the reliability standards, PEC self-reported two noncompliances and PEF self-reported three noncompliances. Entities responsible for enforcement of mandatory reliability standards have proposed that entities that self-reported noncompliance prior to the effective date and pursue aggressive mitigation plans will not be assessed fines. Subsequent to the effective date, PEC self-reported three noncompliances with voluntary standards and PEF self-reported one noncompliance with voluntary standards and one noncompliance with a mandatory standard. PEC and PEF have submitted mitigation plans to address the self-reported noncompliance. The costs of executing the mitigation plans are not expected to have a significant effect on our results of operations or liquidity.

Legal

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

Increasing Energy Demand

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

We are actively pursuing expansion of our energy-efficiency and conservation programs as energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. Our energy-efficiency program provides simple, low-cost ways for residential customers to reduce energy use, promotes home energy checks, provides tools and programs for large and small businesses to minimize their energy use and provides an interactive internet Web site with online calculators, programs and efficiency tips.

We are actively engaged in a variety of alternative energy projects, including solar, hydrogen, biomass and landfill-gas technologies. We are evaluating the feasibility of producing electricity from hog waste and other plant or animal sources.

In the coming years, we will continue to invest in existing plants and consider plans for building new generating plants. Due to the anticipated growth in our service territories, we estimate that we will require new generation facilities in both Florida and the Carolinas toward the end of the next decade, and we are evaluating the best available options for this generation, including advanced design nuclear and gas technologies. At this time, no definitive decisions have been made to construct new nuclear plants. While we pursue expansion of energy-efficiency and conservation programs, PEC has announced a two-year moratorium on constructing new coal-fired plants and that if PEC goes ahead with a new nuclear plant, the new plant would not be online until at least 2018 (see "Nuclear" below).

As authorized under EPACT, on October 4, 2007, the United States Department of Energy (DOE) published final regulations for the disbursement of up to $13 billion in loan guarantees for clean-energy projects using innovative technologies. The guarantees, which will cover up to 100 percent of the amount of any loan for no more than 80 percent of the project cost, are expected to spur development of nuclear, clean-coal and ethanol projects. Congress has approved $4 billion in loan guarantees, with the DOE seeking an additional $9 billion in loan guarantees in its fiscal 2008 budget request. Initial applications for loan guarantees were for non-nuclear projects but it is expected that approval of additional funding could result in guarantees being available for nuclear generation projects. We cannot predict the outcome of this matter.

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.

On November 14, 2006, PEC filed an application with the NRC for a 20-year extension of the Harris operating license. The license renewal application for Harris is currently under review by the NRC with a decision expected in 2008.

Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs and certain other modifications (See Notes 5 and 22D).

We previously announced that we are pursuing development of COL applications to potentially construct new nuclear plants in North Carolina and Florida. Filing of a COL is not a commitment to build a nuclear plant but is a necessary step to keep open the option of building a plant or plants. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We have 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. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, the new plant would not be online until at least 2018 (See "Increasing Energy Demand" above).

On December 12, 2006, we announced that PEF selected a site in Levy County, Fla., to evaluate for possible future nuclear expansion. We have selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. PEF expects to file the application for the COL in 2008. If we receive approval from the NRC and applicable state agencies, and if the decision to build is made, safety-related construction activities could begin as early as 2012, and a new plant could be online in 2016 (See "Increasing Energy Demand" above). In 2007, PEF completed the purchase of approximately 5,000 acres for the Levy County site and associated transmission needs. PEF anticipates filing a Determination of Need petition with the FPSC in 2008.

In 2007, both the Levy County Planning Commission and the Board of Commissioners voted unanimously in favor of PEF's requests to change the comprehensive land use plan. The Florida Department of Community Affairs (FDCA) reviewed the proposed changes to the comprehensive land use plan and in their report, the FDCA expressed concerns related to the intensity of use and environmental suitability for some of the proposed amendments impacting PEF's proposed Levy County nuclear site. We anticipate that the Levy County Planning Commission will resolve the FDCA's concerns without impact to the potential project schedule. We cannot predict the outcome of this matter.

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by EPACT. EPACT provides an annual tax credit of 1.8 cents per kWh for nuclear facilities for the first eight years of operation. The credit is limited to the first 6,000 MW of new nuclear generation in the United States and has an annual cap of $125 million per 1,000 MW of national MW capacity limitation allocated to the unit. In April 2006, the IRS provided interim guidance that the 6,000 MW of production tax credits generally will be allocated to new nuclear facilities that file license applications with the NRC by December 31, 2008, had poured safety-related concrete prior to January 1, 2014, and were placed in service before January 1, 2021. There is no guarantee that the interim guidance will be incorporated into the final regulations governing the allocation of production tax credits. Multiple utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant we construct would qualify for these or other incentives. We cannot predict the outcome of this matter.

In accordance with provisions of Florida's comprehensive energy bill enacted in 2006, the FPSC ordered new rules in December 2006 that would allow investor-owned utilities such as PEF to request recovery of certain planning and construction costs of a nuclear power plant prior to commercial operation. The FPSC issued a final rule on February 13, 2007, under which utilities will be allowed to recover prudently incurred siting, preconstruction costs and AFUDC on an annual basis through the capacity cost-recovery clause. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned once 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. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. In addition, the rule will require 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. Also, on February 1, 2007, the FPSC amended its power plant bid rules to, among other things, exempt nuclear power plants from existing bid requirements.

In 2007, the South Carolina legislature ratified new energy legislation, which includes provisions for cost-recovery mechanisms associated with nuclear baseload generation. The North Carolina legislature ratified new energy legislation, which authorizes the NCUC to allow annual prudence reviews of baseload generating plant construction costs and removes the requirement that a public utility prove financial distress before it may include construction work in progress in rate base and adjust rates, accordingly, in a general rate case while a baseload generating plant is under construction (See "Other Matters – Regulatory Environment").

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 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 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 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 these potential claims cannot be predicted. No material claims are currently pending. 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 in accordance with GAAP. 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.

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 would likely result in increased capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require additional reductions in air emissions of nitrogen oxides (NO_x), SO_2, CO_2 and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multipollutant approach to air pollution control could involve significant capital costs that could be material to our financial position or results of operations. Control equipment that will be installed pursuant to the provisions of the Clean Smokestacks Act, CAIR, CAVR and mercury regulation, which are discussed below, may address some of the issues outlined above. CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

The following table contains information about our current estimates of capital expenditures to comply with environmental laws and regulations described below. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. PEC has completed installation of controls to meet the NO_x SIP Call Rule under Section 110 of the Clean Air Act (NO_x SIP Call) requirements. The NO_x SIP Call is not applicable to Florida. Expenditures for the NO_x SIP Call include the cost to install NO_x controls under North Carolina's and South Carolina's programs to comply with the federal eight-hour ozone standard. The air quality controls installed to comply with the NO_x SIP Call and Clean Smokestacks Act will result in a reduction of the costs to meet the CAIR requirements for our North Carolina units at PEC. Our estimates of capital expenditures to comply

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2007
Clean Smokestacks Act	2002–2013	$1,100 – 1,400	$892
CAIR/CAVR/mercury regulation	2005–2018	1,500 – 2,600	333
Total air quality		2,600 – 4,000	1,225
Clean Water Act Section 316(b) [a]		–	–
Total air and water quality		$2,600 – 4,000	$1,225

[a] Compliance plans to meet the requirements of a revised or new implementing rule under Section 316(b) of the Clean Water Act will be determined upon finalization of the rule. See discussion under "Water Quality."

with environmental laws and regulations are subject to periodic review and revision and may vary significantly. The timing and extent of the costs for future projects will depend upon final compliance strategies.

To date, under the first phase of Clean Smokestacks Act emission reductions, all environmental compliance projects at our Asheville Plant and several projects at our Roxboro Plant have been placed in service. The remaining projects at our two largest plants, Roxboro and Mayo, are under construction and are expected to be completed in 2008 and 2009, respectively. The remaining projects to comply with the second phase of emission reductions, which are smaller in scope, have not yet begun. These estimates are currently under review and are conceptual in nature and subject to change.

To date, expenditures at PEF for CAIR/CAVR/mercury regulation primarily relate to environmental compliance projects under construction at CR5 and CR4, which are expected to be placed in service in 2009 and 2010, respectively. See discussion of projects for Crystal River Units No. 1 and No. 2 to meet CAVR beyond-BART requirements below.

New Source Review

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants in an effort to determine whether changes at those facilities were subject to New Source Review (NSR) requirements or New Source Performance Standards under the Clean Air Act. We were asked to provide information to the EPA as part of this initiative and cooperated in supplying the requested information. The EPA has undertaken civil enforcement actions against unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements requiring expenditures by these unaffiliated utilities, several of which were in excess of $1.0 billion. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the companies may seek recovery of the related costs through rate adjustments or similar mechanisms. On April 2, 2007, the U.S. Supreme Court issued a ruling on an appeal of a decision of the U.S. Court of Appeals for the Fourth Circuit, in a case involving an unaffiliated utility. The Fourth Circuit held that NSR applies to projects that result in an increase in maximum hourly emissions. The U.S. Supreme Court rejected the lower court decision and held that the EPA is not required to adopt the maximum hourly emissions test but may use an actual annual emissions test to determine whether NSR applies.

On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Court of Appeals) set aside the EPA's 2003 NSR equipment replacement rule. The rule would have provided a more uniform definition of routine equipment replacement, which is excluded from NSR applicability. The D.C. Court of Appeals denied a request by the EPA for a re-hearing regarding this matter on June 30, 2006. On November 27, 2006, the EPA filed a petition for a writ of certiorari requesting that the U.S. Supreme Court review the decision of the D.C. Court of Appeals. On April 30, 2007, the U.S. Supreme Court denied the EPA's petition. In a previous case decided in late 2005, the D.C. Court of Appeals had also set aside a provision in the NSR rule that had exempted the installation of pollution control projects from review. These projects are now subject to NSR requirements, adding time and cost to the installation process.

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NO_x 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 that is affected by the Clean Smokestacks Act. In March 2007, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets under the Clean Smokestacks Act by the end of 2013, which were approximately

$1.1 billion to $1.4 billion at the time of the filing. The increase in estimated total capital expenditures from the original 2002 estimate of $813 million is primarily due to the higher cost and revised quantities of construction materials, such as concrete and steel, refinement of cost and scope estimates for the current projects, and increases in the estimated inflation factor applied to future project costs. We are continuing to evaluate various design, technology and new generation options that could further change expenditures required by the Clean Smokestacks Act. O&M expenses will significantly increase due to the cost of reagents, additional personnel and general maintenance associated with the equipment. Recent legislation in North Carolina and South Carolina expanded the traditional fuel clause to include the annual recovery of reagents and certain other costs; all other O&M expenses are currently recoverable through base rates. On March 23, 2007, PEC filed a petition with the NCUC regarding future recovery of costs to comply with the Clean Smokestacks Act, and on October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, CUCA and CIGFUR supporting PEC's proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis. See further discussion about the Clean Smokestacks Act in Note 7B. We cannot predict the outcome of this matter.

Two of PEC's largest coal-fired generating units (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. In 2005, PEC entered into an agreement with the joint owner to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification (See Note 21B).

Pursuant to the Clean Smokestacks Act, PEC entered into an agreement with the state of North Carolina to transfer to the state certain NOx and SO_2 emissions allowances that result from compliance with the collective NOx and SO_2 emissions limitations set in the Clean Smokestacks Act. The Clean Smokestacks Act also required the state to undertake a study of mercury and CO_2 emissions in North Carolina. The future regulatory interpretation, implementation or impact of the Clean Smokestacks Act cannot be predicted.

Clean Air Interstate Rule, Clean Air Mercury Rule and Clean Air Visibility Rule

On March 10, 2005, the EPA issued the final CAIR. The EPA's rule requires the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO_2 emissions in order to reduce levels of fine particulate matter and impacts to visibility. The CAIR sets emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2. States were required to adopt rules implementing the CAIR. The EPA approved the North Carolina CAIR on October 5, 2007, the South Carolina CAIR on October 9, 2007, and the Florida CAIR on October 12, 2007.

PEF has joined a coalition of Florida utilities that has filed a challenge to the CAIR as it applies to Florida. A petition for reconsideration and stay and a petition for judicial review of the CAIR were filed on July 11, 2005. On October 27, 2005, the D.C. Court of Appeals issued an order granting the motion for stay of the proceedings. On December 2, 2005, the EPA announced a reconsideration of four aspects of the CAIR, including its applicability to Florida. On March 16, 2006, the EPA denied all pending reconsiderations, allowing the challenge to proceed. While we consider it unlikely that this challenge would eliminate the compliance requirements of the CAIR, it could potentially reduce or delay our costs to comply with the CAIR. Oral argument has been set by the D.C. Court of Appeals for March 25, 2008. On June 29, 2006, the Florida Environmental Regulation Commission adopted the Florida CAIR, which is very similar to the EPA's model rule. An unaffiliated utility challenged the state-adopted rule. On November 7, 2007, the Florida District Court of Appeals ruled against the challenge and in favor of the Florida Department of Environmental Protection. The outcome of these matters cannot be predicted.

On March 15, 2005, the EPA finalized two separate but related rules: the CAMR that sets mercury emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encourages a cap-and-trade approach to achieving those caps, and a delisting rule that eliminated any requirement to pursue a maximum achievable control technology approach for limiting mercury emissions from coal-fired power plants. NOx and SO_2 controls also are effective in reducing mercury emissions. However, according to the EPA, the second phase cap reflects a level of mercury emissions reduction that exceeds the level that would be achieved solely as a co-benefit of controlling NOx and SO_2 under CAIR. The delisting rule was challenged by a number of parties. Sixteen states subsequently petitioned for a review of the EPA's determination confirming the delisting. On February 8, 2008, the D.C. Court of Appeals decided in favor of the petitioners and vacated the delisting determination and the CAMR. The exact impacts of this decision are uncertain until the court's mandate is issued. The three states in which the Utilities operate have adopted mercury regulations implementing CAMR and submitted their state implementation rules to the EPA. It is uncertain how the vacation of the federal CAMR will affect the state rules.

On June 15, 2005, the EPA issued the final CAVR. The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas, including national parks and wilderness areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. The reductions associated with BART begin in 2013. CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of CAIR may be used by states as a BART substitute. Plans for compliance with CAIR and mercury regulation may fulfill BART obligations, but the states could require the installation of additional air quality controls if they do not achieve reasonable progress in improving visibility. On December 4, 2007, the Florida Department of Environmental Protection finalized a Regional Haze implementation rule that requires sources significantly impacting visibility in Class I areas to install additional controls by December 31, 2017. 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, Bartow Unit No. 3 and Crystal River Units No. 1 and No. 2. The outcome of this matter cannot be predicted. On December 12, 2006, the D.C. Court of Appeals decided in favor of the EPA in a case brought by the National Parks Conservation Association that alleges the EPA acted improperly by substituting the requirements of CAIR for BART for NOx and SO_2 from electric generating units in areas covered by CAIR.

PEC and PEF are each developing an integrated compliance strategy to meet all the requirements of the CAIR, CAVR and mercury regulation. We are evaluating various design, technology and new generation options that could change PEC's and PEF's costs to meet the requirements of CAIR, CAVR and mercury regulation.

The integrated compliance strategy PEF anticipates implementing should provide most, but not all, of the NOx reductions required by CAIR. Therefore, PEF anticipates utilizing the cap-and-trade feature of CAIR by purchasing annual and seasonal NOx allowances. Because the emission controls cannot be installed in time to meet CAIR's NOx requirements in 2009, PEF anticipates purchasing a higher level of annual and seasonal allowances in that year. The costs of these allowances would depend on market prices at the time these allowances are purchased. PEF expects to recover the costs of these allowances through its ECRC.

On October 14, 2005, the FPSC approved PEF's petition for the recovery of costs associated with the development and implementation of an integrated strategy to comply with the CAIR, CAMR and CAVR through the ECRC (see discussion above regarding CAMR). On March 31, 2006, PEF filed a series of compliance alternatives with the FPSC to meet these federal environmental rules. At the time, PEF's recommended proposed compliance plan included approximately \$740 million of estimated capital costs expected to be spent through 2016, to plan, design, build and install pollution control equipment at our Anclote and Crystal River plants. On November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR. They also approved cost recovery of prudently incurred costs necessary to achieve this strategy. On June 1, 2007, PEF filed a supplemental petition for approval of its compliance plan and associated contracts and recovery of costs for air pollution control projects, which included approximately \$1.0 billion to \$2.3 billion of estimated capital costs for the range of alternative plans. The estimated capital cost for the recommended plan, which was \$1.26 billion in the June 1, 2007 filing, represents the low end of the range in the table of estimated required environmental expenditures shown above. The difference in costs between the recommended plan and the high end of the range represents the additional costs that may be incurred if pollution controls are required on Crystal River Units No. 1 and No. 2 in order to comply with the requirements of CAVR beyond BART, should reasonable progress in improving visibility not be achieved, as discussed above. The increase from the estimates filed in March 2006 is primarily due to the higher cost of labor and construction materials, such as concrete and steel, and refinement of cost and scope estimates for the current projects. These costs will continue to change depending upon the results of the engineering and strategy development work and/or increases in the underlying material, labor and equipment costs. Subsequent rule interpretations, equipment availability, or the unexpected acceleration of the initial NOx or other compliance dates, among other things, could require acceleration of some projects. The outcome of this matter cannot be predicted.

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

In March 2004, the North Carolina attorney general filed a petition with the EPA, under Section 126 of the Clean Air Act, asking the federal government to force coal-fired power plants in 13 other states, including South Carolina, to reduce their NOx and SO_2 emissions. The state of North Carolina contends these out-of-state emissions interfere with North Carolina's ability to meet national air quality standards for ozone and particulate matter. On March 16, 2006, the EPA issued a final response denying the petition. The EPA's rationale for denial is that compliance with CAIR will reduce the emissions from surrounding states sufficiently to address North Carolina's concerns. On June 26, 2006, the North Carolina attorney general filed a petition in the D.C. Court of Appeals seeking a review of the agency's final action on the petition. The outcome of this matter cannot be predicted.

National Ambient Air Quality Standards

On December 21, 2005, the EPA announced proposed changes to the National Ambient Air Quality Standards (NAAQS) for particulate matter. The EPA proposed to lower the 24-hour standard for particulate matter less than 2.5 microns in diameter (PM 2.5) from 65 micrograms per cubic meter to 35 micrograms per cubic meter. In addition, the EPA proposed to establish a new 24-hour standard of 70 micrograms per cubic meter for particulate matter that is between 2.5 and 10 microns in diameter (PM 2.5-10). The EPA also proposed to eliminate the current standards for particulate matter less than 10 microns in diameter (PM 10). On September 20, 2006, the EPA announced that it is finalizing the PM 2.5 NAAQS as proposed. In addition, the EPA decided not to establish a PM 2.5-10 NAAQS, and it is eliminating the annual PM 10 NAAQS, but the EPA is retaining the 24-hour PM 10 NAAQS. These changes are not expected to result in designation of any additional nonattainment areas in PEC's or PEF's service territories. On December 18, 2006, environmental groups and 13 states filed a joint petition with the D.C. Court of Appeals arguing that the EPA's new particulate matter rule does not adequately restrict levels of particulate matter. The outcome of this matter cannot be predicted.

On June 20, 2007, the EPA announced proposed changes to the NAAQS for ground-level ozone. The EPA proposed to lower the 8-hour primary standard from 0.08 parts per million to a range of 0.070 to 0.075 parts per million. The two alternatives proposed for the secondary standard are to either establish a new cumulative, seasonal standard or set the secondary standard as identical to the proposed primary standard. Depending on air quality improvements expected over the next several years as current federal requirements are implemented, additional nonattainment areas may be designated in PEC's and PEF's service territories. The final rule is expected in March 2008. The outcome of this matter cannot be predicted.

Water Quality

1. General

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

2. Section 316(b) of the Clean Water Act

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. The July 2004 rule required assessment of the baseline environmental effect of withdrawal of cooling water and development of technologies and measures for reducing environmental effects by certain percentages. Additionally, the rule authorized establishment of alternative performance standards where the site-specific costs of achieving the otherwise applicable standards would have been substantially greater than either the benefits achieved or the costs considered by the EPA during the rulemaking.

Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding many provisions of the rule to the EPA. On July 9, 2007, the EPA suspended the rule pending further rulemaking, with the exception of the requirement that permitting authorities establish best available technology controls for minimizing adverse environmental impact at existing cooling water intake structures on a case-by-case, best professional judgment basis. On November 2, 2007, the Utility Water Act Group and several unaffiliated utilities filed petitions for writ of certiorari to the U.S. Supreme Court. On December 3, 2007, 13 states filed an amicus brief in support of the Utility Water Act Group's petition. As a result of these recent 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 once it is established by the EPA. Costs of compliance with a new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our most recent cost estimates to comply with the July 2004 implementing rule were $60 million to $90 million, including $5 million to $10 million at PEC and $55 million to $80 million at PEF. The outcome of this matter cannot be predicted.

3. North Carolina Groundwater Standard

In 2006, the North Carolina Environmental Management Commission granted approval for North Carolina Division of Water Quality (NCDWQ) staff to publish a notice in the North Carolina Register and schedule public hearings regarding the NCDWQ's recommendation to revise the state's groundwater quality standard for arsenic to 0.00002 milligrams/liter from 0.05 milligrams/liter. To date, no further action has been taken by the NCDWQ staff on this matter.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other greenhouse gases. The treaty went into effect on February 16, 2005. The United States has not adopted the Kyoto Protocol, and the Bush administration favors voluntary programs. There are proposals and ongoing studies at the state and federal levels, including the state of Florida, to address global climate change that would regulate CO_2 and other greenhouse gases. See further discussion of the executive orders issued by the governor of Florida to address reduction of greenhouse gas emissions under "Other Matters – Regulatory Environment."

Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol and some additional proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from 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. We have articulated principles that we believe should be incorporated into any global climate change policy. While the outcome of this matter cannot be predicted, we are taking action on this important issue as discussed under "Other Matters – Increasing Energy Demand." In 2007, we issued a corporate responsibility summary report, which discusses our actions, and in 2006, we issued our report to shareholders for an assessment of global climate change and air quality risks and actions. While we participate in the development of a national climate change policy framework, we will continue to actively engage others in our region to develop consensus-based solutions, as we did with the Clean Smokestacks Act.

In a decision issued July 15, 2005, the D.C. Court of Appeals denied petitions for review filed by several states, cities and organizations seeking the regulation by the EPA of CO_2 emissions from new automobiles under the Clean Air Act, holding that the EPA administrator properly exercised his discretion in denying the request for regulation. The U.S. Supreme Court agreed to hear the case and on April 2, 2007, it ruled that the EPA has the authority under the Clean Air Act to regulate CO_2 emissions from new automobiles. The impact of this decision cannot be predicted.

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 mitigate such risk by performing credit reviews using, among other things, publicly available credit ratings of such counterparties (See Note 17).

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 nuclear decommissioning trust 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

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 risk in the transaction is the cost of replacing the agreements at current market rates. We enter into interest rate derivative agreements only with banks with credit ratings of single A or better.

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 at the end of the reporting period using the Bloomberg Financial Markets system.

In accordance with SFAS No. 133, "Accounting for Derivatives and Hedging Activities" (SFAS No. 133), 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, 2007 and 2006, 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 Florida Progress-obligated mandatorily redeemable 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 swaps and interest rate forward contracts, the tables present notional amounts and weighted-average interest rates by contractual maturity dates for 2008 to 2012 and thereafter and the related fair value. Notional amounts are used to calculate the contractual cash flows to be exchanged under the interest rate swaps and the settlement amounts under the interest rate forward contracts. See Note 17 for more information on interest rate derivatives.

During 2007, PEF had entered into a combined $225 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances, which were terminated on September 13, 2007, in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017.

On July 30, 2007, PEC entered into a $50 million notional forward starting swap and on October 24, 2007, PEC

(dollars in millions) December 31, 2007	2008	2009	2010	2011	2012	Thereafter	Total	Fair Value December 31, 2007
Fixed-rate long-term debt	$427	$400	$306	$1,000	$950	$4,865	$7,948	$8,192
Average interest rate	6.67%	5.95%	4.53%	6.96%	6.67%	6.03%	6.20%	
Variable-rate long-term debt	$450	–	$100	–	–	$861	$1,411	$1,411
Average interest rate	5.27%	–	5.69%	–	–	4.45%	4.80%	
Debt to affiliated trust[a]	–	–	–	–	–	$309	$309	$294
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives								
Interest rate forward contracts[b]	$200	–	–	–	–	–	$200	$(12)
Average pay rate	5.41%	–	–	–	–	–	5.41%	
Average receive rate	(c)	–	–	–	–	–	(c)	

[a] FPC Capital I – Quarterly Income Preferred Securities.
[b] $100 million is for anticipated 10-year debt issue hedge maturing on April 1, 2018, and requires mandatory cash settlement on April 1, 2008. The remaining $100 million is for anticipated 30-year debt issue hedge maturing on April 1, 2038, and requires mandatory cash settlement on April 1, 2008.
[c] Rate is 3-month London Inter Bank Offering Rate (LIBOR), which was 4.70% at December 31, 2007.

(dollars in millions) December 31, 2006	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value December 31, 2006
Fixed-rate long-term debt	$324	$427	$400	$306	$1,000	$5,065	$7,522	$7,820
Average interest rate	6.79%	6.67%	5.95%	4.53%	6.96%	6.13%	6.23%	
Variable-rate long-term debt	–	$450	–	$100	–	$861	$1,411	$1,411
Average interest rate	–	5.77%	–	5.82%	–	3.62%	4.47%	
Debt to affiliated trust[a]	–	–	–	–	–	$309	$309	$312
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives								
Pay variable/receive fixed	–	–	–	–	$(50)	–	$(50)	$(1)
Average pay rate	–	–	–	–	(b)	–	(b)	
Average receive rate	–	–	–	–	4.65%	–	4.65%	
Interest rate forward contracts[c]	$100	–	–	–	–	–	$100	$(2)
Average pay rate	5.61%	–	–	–	–	–	5.61%	
Average receive rate	(b)	–	–	–	–	–	(b)	

[a] FPC Capital I – Quarterly Income Preferred Securities.
[b] Rate is 3-month LIBOR, which was 5.36% at December 31, 2006.
[c] Anticipated 10-year debt issue hedges matured on October 1, 2017, and required mandatory cash settlement on October 1, 2007.

entered into $100 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. On September 25, 2007, PEC amended its 10-year forward starting swap in order to move the maturity date from October 1, 2017, to April 1, 2018.

On January 8, 2008, PEF entered into a combined $200 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

On November 7, 2006, Progress Energy commenced a tender offer for up to $550 million aggregate principal amount of its 2011 and 2012 senior notes. Subsequently, we executed a total notional amount of $550 million of reverse treasury locks to reduce exposure to changes in cash flow due to fluctuating interest rates, which were then terminated on December 1, 2006. On December 6, 2006, Progress Energy repurchased, pursuant to the tender offer, $550 million, or 44.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest.

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, 2007 and 2006, the fair value of these funds was $1.384 billion and $1.287 billion, respectively, including $804 million and $735 million, respectively, for PEC and $580 million and $552 million, respectively, for PEF. We actively monitor our portfolio by benchmarking the performance of our investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Utilities' regulated electric rates provide for recovery of these costs net of any trust fund earnings, and, therefore, fluctuations in trust fund marketable security returns do not affect earnings. See Note 13 for further information on the trust fund securities.

Contingent Value Obligations Market Value Risk

In connection with the acquisition of Florida Progress, 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 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. The CVOs are derivatives and are recorded at fair value. Unrealized gains and losses from changes in fair value are recognized in earnings. We perform sensitivity analyses to estimate our exposure to the market risk of the CVOs. The sensitivity analysis 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. At December 31, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively. A hypothetical 10 percent decrease in the December 31, 2007, market price would result in a $3 million decrease in the fair value of the CVOs.

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. We also have oil price risk exposure related to synthetic fuels tax credits as discussed in MD&A – "Other Matters – Synthetic Fuels Tax Credits."

Most of our physical commodity contracts are not derivatives pursuant to SFAS No. 133 or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

We perform sensitivity analyses to estimate our exposure to the market risk of our derivative commodity instruments that are not eligible for recovery from ratepayers. The following discussion addresses the stand-alone commodity risk created by these derivative commodity instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge. The sensitivity analysis performed on these derivative commodity instruments uses quoted prices obtained from brokers to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. At December 31, 2007, the only derivative commodity instruments not eligible for recovery from ratepayers related to derivative contracts entered into on January 8, 2007, to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices as discussed below. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. At December 31, 2006, derivative commodity instruments not eligible for recovery from ratepayers were included in discontinued operations as discussed below.

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

DISCONTINUED OPERATIONS

As discussed in Note 3A, our subsidiary, PVI, entered into a series of transactions to sell or assign substantially all of its CCO physical and commercial assets and liabilities. On June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of the Georgia Contracts, forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represented substantially all of our nonregulated energy marketing and trading operations. The sale of the generation assets closed on June 11, 2007. Additionally, we sold Gas on October 2, 2006 (See Note 3C). At December 31, 2007, with the exception of the oil price hedge instruments discussed below, our discontinued operations did not have outstanding positions in derivative instruments. For the year ended December 31, 2007, $88 million of after-tax gains from derivative instruments related to our nonregulated energy marketing and trading operations were included in discontinued operations on the Consolidated Statements of Income.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Note 3J, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate Ceredo in accordance with FIN 46R, but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. At December 31, 2007, the fair value of all of these contracts was recorded as a $234 million short-term derivative asset position, including $79 million at Ceredo. The fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet (See Note 6A). As discussed in Note 3B, on October 12, 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts. Of this amount, $57 million was attributable to Ceredo of which $42 million was attributed to minority interest for the portion of the gain subsequent to the disposal of Ceredo.

At December 31, 2006, derivative assets of $107 million and derivative liabilities of $31 million were included in assets to be divested and liabilities to be divested, respectively, on the Consolidated Balance Sheet. Due to the divestitures discussed above, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts would be fulfilled and cash flow hedge accounting for the contracts was discontinued beginning in the second quarter of 2006 for Gas and in the fourth quarter of 2006 for CCO. Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. For the years ended December 31, 2006 and 2005, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ended December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ended December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges.

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. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets on the Balance Sheets, respectively, until the contracts are settled (See Note 7A). Once settled, any realized gains or losses are passed through the fuel clause. During the year ended December 31, 2007, PEC recorded a net realized loss of $9 million. PEC's net realized gains and losses were not material during the years ended December 31, 2006 and 2005. During the years ended December 31, 2007, 2006 and 2005, PEF recorded a net realized loss of $46 million, a net realized gain of $39 million and a net realized gain of $70 million, respectively.

Excluding amounts receiving regulatory accounting treatment and amounts related to our discontinued operations discussed above, gains and losses from contracts entered into for economic hedging purposes were not material to our results of operations during the years ended December 31, 2007, 2006 and 2005. Excluding derivative assets and derivative liabilities to be divested discussed above, we did not have material outstanding positions in such contracts at December 31, 2007 and 2006, other than those receiving regulatory accounting treatment at PEC and PEF, as discussed below.

At December 31, 2007, the fair value of PEC's commodity derivative instruments was recorded as a $19 million long-term derivative asset position included in other assets and deferred debits and a $3 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, PEC did not have material outstanding positions in such contracts.

At December 31, 2007, the fair value of PEF's commodity derivative instruments was recorded as a $60 million short-term derivative asset position included in prepayments and other current assets, a $90 million long-term derivative asset position included in derivative assets, and a $15 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, the fair value of such instruments was recorded as a $2 million long-term derivative asset position included in derivative assets, an $87 million short-term derivative liability position included in other current liabilities, and a $36 million long-term derivative liability position included in other liabilities and deferred credits on the Consolidated Balance Sheet.

CASH FLOW HEDGES

Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. At December 31, 2007 and 2006, we did not have material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our results of operations for 2007, 2006 and 2005.

At December 31, 2007 and 2006, the amount recorded in our accumulated other comprehensive income related to commodity cash flow hedges was not material.

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, 2007. 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 Committee of the board of directors.

Based on our assessment, management determined that, at December 31, 2007, 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, 2007, as stated in their report.

William D. Johnson

William D. Johnson
Chairman, President and Chief Executive Officer

Peter M. Scott III

Peter M. Scott III
Executive Vice President and Chief Financial Officer

February 28, 2008

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., (the Company) as of December 31, 2007, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, 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 at December 31, 2007, 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, 2007, of the Company and our report dated February 28, 2008, expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph concerning the adoption of new accounting principles in 2007 and 2006.

Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Progress Energy, Inc.

We have audited the accompanying consolidated balance sheets of Progress Energy, Inc., and its subsidiaries (the Company) at December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 14 and Note 16 to the consolidated financial statements, on January 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48 and on December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158.

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 at December 31, 2007, 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, 2008, expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2008

CONSOLIDATED STATEMENTS OF INCOME

(in millions except per share data)			
Years ended December 31	**2007**	2006	2005
Operating revenues	**$9,153**	$8,724	$7,948
Operating expenses			
Fuel used in electric generation	**3,145**	3,008	2,359
Purchased power	**1,184**	1,100	1,048
Operation and maintenance	**1,842**	1,583	1,770
Depreciation and amortization	**905**	1,011	926
Taxes other than on income	**501**	500	460
Other	**30**	35	(3)
Total operating expenses	**7,607**	7,237	6,560
Operating income	**1,546**	1,487	1,388
Other income (expense)			
Interest income	**34**	59	13
Other, net	**44**	(16)	(1)
Total other income	**78**	43	12
Interest charges			
Net interest charges	**605**	631	588
Allowance for borrowed funds used during construction	**(17)**	(7)	(13)
Total interest charges, net	**588**	624	575
Income from continuing operations before income tax and minority interest	**1,036**	906	825
Income tax expense	**334**	339	298
Income from continuing operations before minority interest	**702**	567	527
Minority interest in subsidiaries' income, net of tax	**(9)**	(16)	(4)
Income from continuing operations	**693**	551	523
Discontinued operations, net of tax	**(189)**	20	173
Cumulative effect of change in accounting principle, net of tax	**–**	–	1
Net income	**$504**	$571	$697
Average common shares outstanding – basic	**256**	250	247
Basic earnings per common share			
Income from continuing operations	**$2.71**	$2.20	$2.12
Discontinued operations, net of tax	**(0.74)**	0.08	0.70
Net income	**$1.97**	$2.28	$2.82
Diluted earnings per common share			
Income from continuing operations	**$2.70**	$2.20	$2.12
Discontinued operations, net of tax	**(0.74)**	0.08	0.70
Net income	**$1.96**	$2.28	$2.82
Dividends declared per common share	**$2.45**	$2.43	$2.38

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2007	2006
ASSETS		
Utility plant		
Utility plant in service	$25,327	$23,743
Accumulated depreciation	(10,895)	(10,064)
Utility plant in service, net	14,432	13,679
Held for future use	37	10
Construction work in progress	1,765	1,289
Nuclear fuel, net of amortization	371	267
Total utility plant, net	16,605	15,245
Current assets		
Cash and cash equivalents	255	265
Short-term investments	1	71
Receivables, net	1,137	930
Inventory	994	936
Deferred fuel cost	154	196
Deferred income taxes	27	142
Assets to be divested	52	966
Prepayments and other current assets	155	108
Total current assets	2,775	3,614
Deferred debits and other assets		
Regulatory assets	931	1,231
Nuclear decommissioning trust funds	1,384	1,287
Miscellaneous other property and investments	448	465
Goodwill	3,655	3,655
Derivative assets	109	2
Other assets and deferred debits	379	208
Total deferred debits and other assets	6,906	6,848
Total assets	$26,286	$25,707
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 260 million and 256 million shares issued and outstanding, respectively	$6,028	$5,791
Unearned ESOP shares (2 million shares)	(37)	(50)
Accumulated other comprehensive loss	(34)	(49)
Retained earnings	2,465	2,594
Total common stock equity	8,422	8,286
Preferred stock of subsidiaries – not subject to mandatory redemption	93	93
Minority interest	84	10
Long-term debt, affiliate	271	271
Long-term debt, net	8,466	8,564
Total capitalization	17,336	17,224
Current liabilities		
Current portion of long-term debt	877	324
Short-term debt	201	–
Accounts payable	789	712
Interest accrued	173	171
Dividends declared	160	156
Customer deposits	255	227
Regulatory liabilities	173	76
Liabilities to be divested	8	248
Income taxes accrued	8	284
Other current liabilities	604	622
Total current liabilities	3,248	2,820
Deferred credits and other liabilities		
Noncurrent income tax liabilities	361	312
Accumulated deferred investment tax credits	139	151
Regulatory liabilities	2,539	2,543
Asset retirement obligations	1,378	1,304
Accrued pension and other benefits	763	957
Capital lease obligations	239	70
Other liabilities and deferred credits	283	326
Total deferred credits and other liabilities	5,702	5,663
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$26,286	$25,707

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions) Years ended December 31	2007	2006	2005
Operating activities			
Net income	**$504**	$571	$697
Adjustments to reconcile net income to net cash provided by operating activities			
Impairment of assets	–	174	–
Charges for voluntary enhanced retirement program	–	–	159
Depreciation and amortization	**1,026**	1,190	1,216
Deferred income taxes and investment tax credits, net	**177**	(251)	(340)
Deferred fuel cost (credit)	**117**	396	(317)
Deferred income	**(128)**	(69)	–
Other adjustments to net income	**124**	88	135
Cash (used) provided by changes in operating assets and liabilities			
Receivables	**(193)**	78	(170)
Inventory	**(11)**	(168)	(163)
Prepayments and other current assets	**23**	(92)	(13)
Income taxes, net	**(275)**	197	101
Accounts payable	**(34)**	16	124
Other current liabilities	**150**	(30)	65
Other assets and deferred debits	**(221)**	(60)	(78)
Other liabilities and deferred credits	**(7)**	(39)	51
Net cash provided by operating activities	**1,252**	2,001	1,467
Investing activities			
Gross property additions	**(1,973)**	(1,572)	(1,313)
Nuclear fuel additions	**(228)**	(114)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	**675**	1,657	475
Purchases of available-for-sale securities and other investments	**(1,413)**	(2,452)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	**1,452**	2,631	3,845
Other investing activities	**30**	(23)	(40)
Net cash (used) provided by investing activities	**(1,457)**	127	(1,144)
Financing activities			
Issuance of common stock	**151**	185	208
Dividends paid on common stock	**(627)**	(607)	(582)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	**176**	–	–
Net increase (decrease) in short-term debt	**25**	(175)	(509)
Proceeds from issuance of long-term debt, net	**739**	397	1,642
Retirement of long-term debt	**(324)**	(2,200)	(564)
Other financing activities	**55**	(68)	32
Net cash provided (used) by financing activities	**195**	(2,468)	227
Net (decrease) increase in cash and cash equivalents	**(10)**	(340)	550
Cash and cash equivalents at beginning of year	**265**	605	55
Cash and cash equivalents at end of year	**$255**	$265	$605
Supplemental disclosures			
Cash paid during the year			
Interest (net of amount capitalized)	**$585**	$698	$645
Income taxes (net of refunds)	**176**	311	168
Significant noncash transactions			
Capital lease obligation incurred	**182**	54	–
Note receivable for disposal of ownership interest in Ceredo	**48**	–	–
Noncash property additions accrued for as of December 31	**329**	231	116

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(in millions)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned Restricted Shares	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2004	247	$5,360	$(13)	$(76)	$(164)	$2,526	$7,633
Net income		–	–	–	–	697	697
Other comprehensive income		–	–	–	60	–	60
Comprehensive income							757
Issuance of shares	5	199	–	–	–	–	199
Presentation reclassification – SFAS No. 123R adoption		(13)	13	–	–	–	–
Stock options exercised		8	–	–	–	–	8
Purchase of restricted stock		(8)	–	–	–	–	(8)
Allocation of ESOP shares		12	–	13	–	–	25
Stock-based compensation expense		13	–	–	–	–	13
Dividends ($2.38 per share)		–	–	–	–	(589)	(589)
Balance, December 31, 2005	252	5,571	–	(63)	(104)	2,634	8,038
Net income		–	–	–	–	571	571
Other comprehensive loss		–	–	–	(18)	–	(18)
Comprehensive income							553
Adjustment to initially apply SFAS No. 158, net of tax		–	–	–	73	–	73
Issuance of shares	4	70	–	–	–	–	70
Stock options exercised		115	–	–	–	–	115
Purchase of restricted stock		(8)	–	–	–	–	(8)
Allocation of ESOP shares		13	–	13	–	–	26
Stock-based compensation expense		30	–	–	–	–	30
Dividends ($2.43 per share)		–	–	–	–	(611)	(611)
Balance, December 31, 2006	256	5,791	–	(50)	(49)	2,594	8,286
Net income		–	–	–	–	504	504
Other comprehensive income		–	–	–	15	–	15
Comprehensive income							519
Adjustment to initially apply FASB Interpretation No. 48		–	–	–	–	(2)	(2)
Issuance of shares	4	46	–	–	–	–	46
Stock options exercised		105	–	–	–	–	105
Allocation of ESOP shares		15	–	13	–	–	28
Stock-based compensation expense		71	–	–	–	–	71
Dividends ($2.45 per share)		–	–	–	–	(631)	(631)
Balance, December 31, 2007	260	$6,028	$–	$(37)	$(34)	$2,465	$8,422

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions) Years ended December 31	2007	2006	2005
Net income	$504	$571	$697
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax (expense) benefit of $(3), $28 and $(26), respectively)	4	(46)	46
Foreign currency translation adjustments included in discontinued operations	–	–	(6)
Minimum pension liability adjustment included in discontinued operations (net of tax expense of $1)	–	–	1
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $1)	2	–	–
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $8, $16 and $(26), respectively)	(13)	(23)	37
Net unrecognized items on pension and other postretirement benefits (net of tax expense of $16)	23	–	–
Minimum pension liability adjustment (net of tax (expense) benefit of $(30) and $22, respectively)	–	48	(19)
Other (net of tax benefit (expense) of $3, $- and $(1), respectively)	(1)	3	1
Other comprehensive income (loss)	15	(18)	60
Comprehensive income	$519	$553	$757

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

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

PEC and PEF are regulated public utilities primarily engaged in the generation, transmission, distribution and sale of electricity. PEC is subject to the regulatory provisions of the North Carolina Utilities Commission (NCUC), Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC) and the FERC. PEF is subject to the regulatory provisions 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) and include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy, and as such their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements. Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in minority interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for minority interest are reported on a net of tax basis if the underlying subsidiary is structured as a taxable entity.

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

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

These combined notes accompany and form an integral part of our consolidated financial statements.

Certain amounts for 2006 and 2005 have been reclassified to conform to the 2007 presentation. In addition, our 2007 presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under SFAS No. 95, "Statement of Cash Flows." Previously, we had provided separate disclosure of cash flows from continuing operations and discontinued operations. These changes in cash flow presentations had no impact on total cash and cash equivalents, net change in cash and cash equivalents, or results of operations.

C. Consolidation of Variable Interest Entities

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

Interest Entities – An Interpretation of ARB No. 51" (FIN 46R).

In addition to the variable interests listed below for PEC and PEF, we have interests through other subsidiaries in several variable interest entities for which we are not the primary beneficiary. These arrangements include investments in five limited liability partnerships and limited liability corporations. At December 31, 2007, the aggregate additional maximum loss exposure that we could be required to record in our income statement as a result of these arrangements was $6 million, which represents our net remaining investment in the entities. The creditors of these variable interest entities do not have recourse to our general credit in excess of the aggregate maximum loss exposure.

PEC is the primary beneficiary of, and consolidates, two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Internal Revenue Code (the Code). At December 31, 2007, the total assets of the two entities were $37 million, the majority of which are collateral for the entities' obligations and are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

PEC has an interest in and consolidates a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. PEC has requested the necessary information to determine if the 17 partnerships are variable interest entities or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC and, accordingly, PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the 17 partnerships. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the entities would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows.

PEC also has an interest in one power plant resulting from long-term power purchase contracts. Our only significant exposure to variability from these contracts results from fluctuations in the market price of fuel used by the entity's plants to produce the power purchased by PEC. We are able to recover these fuel costs under PEC's fuel clause. Total purchases from this counterparty were $39 million, $45 million and $44 million in 2007, 2006 and 2005, respectively. The generation capacity of the entity's power plant is approximately 847 megawatts (MW). PEC has requested the necessary information to determine if the power plant owner is a variable interest entity or to identify the primary beneficiary. The entity declined to provide us with the necessary financial information and PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the power plant. PEC believes that if it is determined to be the primary beneficiary of the entity, the effect of consolidating the entity would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparty, the impact cannot be determined at this time.

PEC also has interests in several other variable interest entities for which PEC is not the primary beneficiary. These arrangements include investments in 21 limited liability partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. At December 31, 2007, the aggregate maximum loss exposure that PEC could be required to record on its income statement as a result of these arrangements totals $19 million, which primarily represents its net remaining investment in these entities. The creditors of these variable interest entities do not have recourse to the general credit of PEC in excess of the aggregate maximum loss exposure.

PEF has interests in four variable interest entities for which PEF is not the primary beneficiary. These arrangements include investments in one venture capital fund, one limited liability corporation, one building lease with a special-purpose entity and one operating lease with a special-purpose entity. At December 31, 2007, the aggregate maximum loss exposure that PEF could be required to record in its income statement as a result of these arrangements was $56 million. The majority of this exposure is related to a prepayment clause in the building lease and is not considered equity at risk. The creditors of these variable interest entities do not have recourse to the general credit of PEF in excess of the aggregate maximum loss exposure.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

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

FUEL COST DEFERRALS

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

EXCISE TAXES

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for sales and use tax on a net basis and gross receipts tax, franchise taxes and other excise taxes on a gross basis. The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income on the Consolidated Statements of Income were $299 million, $293 million and $258 million for the years ended December 31, 2007, 2006 and 2005, respectively.

STOCK-BASED COMPENSATION

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

RELATED PARTY TRANSACTIONS

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

UTILITY PLANT

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

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

ASSET RETIREMENT OBLIGATIONS

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

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

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

Substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 5A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization of utility assets (See Note 7).

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

The North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in 2002. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended in December 2007, unless there were extraordinary events beyond the control of the utilities or unless the utilities persistently earned a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. There were no adjustments to PEC's base rates during the five-year period ended December 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation. During the rate freeze period, the legislation provided for the amortization and recovery of 70 percent of the original estimated compliance costs for the Clean Smokestacks Act while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. During 2007, the NCUC approved PEC's request to amortize the remaining 30 percent of the original estimated compliance costs during 2008 and 2009, with discretion to amortize up to $174 million in either year.

CASH AND CASH EQUIVALENTS

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

INVENTORY

We account for inventory, including emission allowances, using the average cost method. 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. We value inventory of nonregulated subsidiaries at the lower of cost or market.

REGULATORY ASSETS AND LIABILITIES

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

GOODWILL AND INTANGIBLE ASSETS

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

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

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

INCOME TAXES

Deferred income taxes have been provided for temporary differences. These occur when there are differences between the book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. Credits for the production and sale of synthetic fuels are deferred credits to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns, and are included in income tax expense (benefit) of discontinued operations in the Consolidated Statements of Income. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority, including resolutions of any related appeals or litigation processes, based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount of the tax benefit that, in our judgment, is greater than 50 percent likely to be realized. Interest expense on tax deficiencies and uncertain tax positions is included in net interest charges, and tax penalties are included in other, net on the Consolidated Statements of Income.

DERIVATIVES

We account for derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as assets or liabilities in the balance sheet and measure those instruments at fair value, unless the derivatives meet the SFAS No. 133 criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the SFAS No. 133 criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related SFAS No. 133 hedge criteria are met. Certain economic derivative instruments receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. See Note 17 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

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

As discussed in Note 21, we accrue environmental remediation liabilities when the criteria for SFAS No. 5 have been met. 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. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable 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

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

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

SUBSIDIARY STOCK TRANSACTIONS

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

2. NEW ACCOUNTING STANDARDS

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes"

Refer to Note 14 for information regarding our first quarter 2007 implementation of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48).

SFAS No. 157, "Fair Value Measurements"

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), which redefines 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." SFAS No. 157 establishes a framework for measuring fair value and a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. The effective date of SFAS No. 157 for us is January 1, 2008. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, which for us delays the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except for those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until January 1, 2009. We will implement SFAS No. 157 as of January 1, 2008, and will utilize the deferral provision of FSP No. FAS 157-2 for all nonfinancial assets and liabilities within its scope. We do not expect the adoption of SFAS No. 157 to have a material impact on our financial position or results of operations.

SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115"

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

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

FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" (FIN 39), specifies what conditions must be met for an entity to have the right to offset assets and liabilities in the balance sheet and clarifies when it is appropriate to offset amounts recognized for forward interest rate swap, currency swap option, and other conditional or exchange contracts. FIN 39 also permits offsetting of fair value amounts recognized for multiple contracts executed with the same counterparty under a master netting arrangement. On April 30, 2007, the FASB issued FASB Staff Position FIN No. 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts" (FSP FIN 39-1), which amends portions of FIN 39 to make certain terms consistent with those used in SFAS No. 133. FSP FIN 39-1 also amends FIN 39 to allow for the offsetting of fair value amounts for the right to reclaim collateral assets or liabilities arising from the same master netting arrangement as the derivative instruments. We will implement the FSP as of January 1, 2008, as a retrospective change in accounting principle for all financial statements presented. We currently offset fair value amounts recognized for derivative instruments under master netting arrangements. As allowed under FSP FIN 39-1, we will change our accounting policy effective January 1, 2008, and discontinue the offset of fair value amounts for such derivatives. We expect this change in policy to result in increases to total derivative assets and liabilities and accounts receivables and payables of $64 million as of adoption on January 1, 2008, but will have no impact on our results of operations or equity.

SFAS No. 141R, "Business Combinations"

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

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

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

3. DIVESTITURES

A. CCO – Georgia Operations

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

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

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of CCO as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007, 2006 and 2005 was $11 million, $36 million and $39 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. After-tax depreciation expense during each of the years ended December 31, 2006 and 2005 was $14 million. Results of discontinued operations for CCO for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$407**	$754	$627
Loss before income taxes	**$(449)**	$(92)	$(93)
Income tax benefit	**166**	35	39
Net loss from discontinued operations	**(283)**	(57)	(54)
Gain (loss) on disposal of discontinued operations, including income tax benefit of $7 and $123, respectively	**18**	(226)	–
Loss from discontinued operations	**$(265)**	$(283)	$(54)

B. Terminals Operations and Synthetic Fuels Businesses

On December 24, 2007, we signed an agreement to sell coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. Terminals was previously a component of our former Coal and Synthetic Fuels segment. The terminals have a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale are expected to be used for general corporate purposes. We expect this transaction to close by the end of the first quarter of 2008.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of Terminals as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007, 2006 and 2005 was $1 million, $1 million and $3 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in November 2007. After-tax depreciation expense during each of the years ended December 31, 2007, 2006 and 2005 was $2 million, $4 million and $7 million, respectively.

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels (Synthetic Fuels) as defined under Section 29 of the Code. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. Synthetic fuels are generally not economical to produce and sell absent the credits. On September 14, 2007, we idled production of synthetic fuels at our majority-owned synthetic fuels facilities due to the high level of oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007, and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. 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. In accordance with the provisions of SFAS No. 144, a long-lived asset is abandoned when it ceases to be used. The accompanying consolidated income statements have been restated for all periods presented to reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Results of discontinued operations for the years ended December 31 for Terminals and Synthetic Fuels were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$1,126**	$847	$1,220
Earnings (loss) before income taxes and minority interest	**$2**	$(179)	$(171)
Income tax benefit, including tax credits	**64**	135	336
Minority interest share of losses	**17**	7	33
Net earnings (loss) from discontinued operations	**$83**	$(37)	$198

C. Natural Gas Drilling and Production

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

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

The accompanying consolidated financial statements reflect the operations of Gas as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for each of the years ended December 31, 2006, and 2005 was $13 million. We ceased recording depreciation upon classification of the assets as discontinued operations in July 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $16 million and $26 million, respectively. Results of discontinued operations for Gas for the years ended December 31 were as follows:

(in millions)	2007	2006	2005
Revenues	$–	$192	$159
Earnings before income taxes	$–	$135	$73
Income tax benefit (expense)	4	(53)	(25)
Net earnings from discontinued operations	4	82	48
(Loss) gain on disposal of discontinued operations, including income tax benefit (expense) of $1 and $(188), respectively	(2)	300	–
Earnings from discontinued operations	$2	$382	$48

D. CCO – DeSoto and Rowan Generation Facilities

On May 2, 2006, our board of directors approved a plan to divest of two subsidiaries of PVI, DeSoto County Generating Co., LLC (DeSoto) and Rowan County Power, LLC (Rowan). DeSoto owned a 320 MW dual-fuel combustion turbine electric generation facility in DeSoto County, Fla., and Rowan owned a 925 MW dual-fuel combined cycle and combustion turbine electric generation facility in Rowan County, N.C. On May 8, 2006, we entered into definitive agreements to sell DeSoto and Rowan, including certain existing power supply contracts, to Southern Power Company, a subsidiary of Southern Company, for gross purchase prices of approximately $80 million and $325 million, respectively. We used the proceeds from the sales to reduce debt and for other corporate purposes.

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

The accompanying consolidated financial statements reflect the operations of DeSoto and Rowan as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2006, and 2005 was $6 million and $13 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in May 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $3 million and $8 million, respectively. Results of discontinued operations for DeSoto and Rowan for the years ended December 31 were as follows:

(in millions)	2006	2005
Revenues	$64	$67
Earnings before income taxes	$15	$5
Income tax expense	(5)	(2)
Net earnings from discontinued operations	10	3
Loss on disposal of discontinued operations, including income tax benefit of $37	(67)	–
(Loss) earnings from discontinued operations	$(57)	$3

E. Progress Telecom, LLC

On March 20, 2006, we completed the sale of Progress Telecom, LLC (PT LLC) to Level 3 Communications, Inc. (Level 3). We received gross proceeds comprised of cash of $69 million and approximately 20 million shares of Level 3 common stock valued at an estimated $66 million on the date of the sale. Our net proceeds from the sale of approximately $70 million, after consideration of minority interest, were used to reduce debt. Prior to the sale, we had a 51 percent interest in PT LLC. See Note 20 for a discussion of the subsequent sale of the Level 3 stock in 2006.

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

The accompanying consolidated financial statements reflect the operations of PT LLC as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated was $1 million for the year ended December 31, 2005. We ceased recording depreciation upon classification of the assets as discontinued operations in January 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $1 million and $8 million, respectively. Results of discontinued operations for PT LLC for the years ended December 31 were as follows:

(in millions)	2006	2005
Revenues	$18	$76
Earnings before income taxes and minority interest	$7	$11
Income tax expense	(4)	(3)
Minority interest share of earnings	(5)	(4)
Net (loss) earnings from discontinued operations	(2)	4
Gain on disposal of discontinued operations, including income tax expense of $8 and minority interest of $35	28	–
Earnings from discontinued operations	$26	$4

In connection with the sale, PEC and PEF provided indemnification against costs associated with certain asset performances to Level 3. See general discussion of guarantees at Note 22C. The ultimate resolution of these matters could result in adjustments to the gain on sale in future periods.

F. Dixie Fuels and Other Fuels Business

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

The accompanying consolidated financial statements reflect Dixie Fuels and the other fuels business as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated was $1 million for each of the years ended December 31, 2006, and 2005. We ceased recording depreciation upon classification of the assets as discontinued operations. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $1 million and $2 million, respectively. Results of discontinued operations for Dixie Fuels and other fuels businesses for the years ended December 31 were as follows:

(in millions)	2007	2006	2005
Revenues	$–	$20	$32
Earnings before income taxes	$–	$11	$8
Income tax expense	–	(4)	(3)
Net earnings from discontinued operations	–	7	5
Gain on disposal of discontinued operations, including income tax expense of $1 and $1, respectively	2	2	–
Earnings from discontinued operations	$2	$9	$5

G. Coal Mining Businesses

Progress Fuels owned five subsidiaries engaged in the coal mining business. These businesses were previously included in our former Coal and Synthetic Fuels business segment. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an after-tax loss of $10 million on the sale of these assets.

On December 24, 2007, we signed an agreement to sell the remaining net assets of the coal mining business for gross cash proceeds of $23 million. These assets include Powell Mountain Coal Co. and Dulcimer Land Co., which consist of about 30,000 acres in Lee County, Va. and Harlan County, Ky. The property contains an estimated 40 million tons of high quality coal reserves. We expect this transaction to close by the end of the first quarter of 2008.

The accompanying consolidated financial statements reflect the coal mining operations as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of the coal mines, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007, 2006 and 2005 was $1 million, $1 million and $3 million, respectively. We ceased recording depreciation expense upon classification of the coal mining operations as discontinued operations in November 2005. After-tax depreciation expense during the year ended December 31, 2005, was $10 million. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$28**	$84	$184
Loss before income taxes	**$(17)**	$(11)	$(16)
Income tax benefit	**6**	7	5
Net loss from discontinued operations	**(11)**	(4)	(11)
Loss on disposal of discontinued operations, including income tax benefit of $16	**–**	(10)	–
Loss from discontinued operations	**$(11)**	$(14)	$(11)

H. Progress Rail

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

Based on the gross proceeds associated with the sale of $429 million, we recorded an estimated after-tax loss on disposal of $25 million during the year ended December 31, 2005. During the year ended December 31, 2006, we recorded an additional after-tax loss on disposal of $6 million in connection with guarantees and indemnifications provided by Progress Fuels and Progress Energy for certain legal, tax and environmental matters to One Equity Partners LLC. The ultimate resolution of these matters could result in adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

The accompanying consolidated financial statements reflect the operations of Progress Rail as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of Progress Rail, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the year ended December 31, 2005, was $4 million.

We ceased recording depreciation upon classification of Progress Rail as discontinued operations in February 2005. After-tax depreciation expense during the year ended December 31, 2005, was $3 million. Results of discontinued operations for Progress Rail for the years ended December 31 were as follows:

(in millions)	2006	2005
Revenues	$–	$358
Earnings before income taxes	$–	$8
Income tax expense	–	(3)
Net earnings from discontinued operations	–	5
Loss on disposal of discontinued operations, including income tax (expense) benefit of $(6) and $15, respectively	(6)	(25)
Loss from discontinued operations	$(6)	$(20)

I. Net Assets to be Divested

At December 31, 2007, the assets and liabilities of Terminals and the remaining assets and liabilities of the coal mining operations were included in net assets to be divested. At December 31, 2006, the assets and liabilities of CCO, Terminals, the remaining coal mining operations and other fuels businesses were included in net assets to be divested. The major balance sheet classes included in assets and liabilities to be divested in the Consolidated Balance Sheets were as follows:

(in millions)	**December 31, 2007**	December 31, 2006
Accounts receivable	**$–**	$44
Inventory	**6**	56
Other current assets	**2**	45
Property, plant and equipment, net	**38**	595
Other assets	**6**	226
Assets to be divested	**$52**	$966
Accounts payable	**$–**	$43
Accrued expenses	**3**	179
Long-term liabilities	**5**	26
Liabilities to be divested	**$8**	$248

J. Ceredo Synthetic Fuels Interests

On March 30, 2007, our Progress Fuels subsidiary disposed of its 100 percent ownership interest in Ceredo Synfuel LLC (Ceredo), a subsidiary that produces and sells qualifying coal-based solid synthetic fuels, to a third-party buyer. In addition, we entered into an agreement to operate the Ceredo facility on behalf of the buyer. At closing, we received cash proceeds of $10 million and a non-recourse note receivable of $54 million. Payments on the note are due as we produce and sell qualifying synthetic fuels on behalf of the buyer. In accordance with the terms of the agreement, we received payments on the note related to 2007 production of $49 million in 2007 and $5 million in 2008. The total amount of proceeds is subject to adjustment once the final value of the 2007 Section 29/45K credits is known. The note bears interest at a rate equal to the three-month London Inter Bank Offering Rate (LIBOR) rate plus 1%. The estimated fair value of the note at the inception of the transaction was $48 million.

Pursuant to the terms of the disposal agreement, the buyer had the right to unwind the transaction if an Internal Revenue Service (IRS) reconfirmation private letter ruling was not received by November 9, 2007, or if certain adverse changes in tax law, as defined in the agreement, occurred before November 19, 2007. The IRS reconfirmation private letter ruling was received on October 29, 2007, and no adverse change in tax law occurred prior to November 19, 2007. As of December 31, 2007, due to indemnification provisions discussed below, we recorded losses on disposal of $3 million based on the estimated value of the 2007 Section 29/45K tax credits. The operations of Ceredo have been reclassified to discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3B.

On the date of the transaction, the carrying value of the disposed ownership interest totaled $37 million, which consisted primarily of the fair value of crude oil call options purchased in January 2007. Subsequent to the disposal, we remained the primary beneficiary of Ceredo and continued to consolidate Ceredo in accordance with FIN 46R, but recorded a 100 percent minority interest. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer. The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods. See general discussion of guarantees at Note 22C.

K. Winter Park Distribution Assets

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

L. Synthetic Fuels Partnership Interests

In two June 2004 transactions, Progress Fuels sold a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of its synthetic fuels facilities. Substantially all proceeds from the sales were received over time, which is typical of such sales in the industry. Gains from the sales were recognized on a cost-recovery basis. The book value of the interests sold totaled approximately $5 million. We recognized gains on these transactions of $4 million and $30 million in the years ended December 31, 2006, and 2005, respectively. In 2007, due to the increase in the price of oil that limits synthetic fuels tax credits, we did not record any additional gains. The operations of Colona have been reclassified to discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3B.

4. ACQUISITIONS

In May 2005, Winchester Production, an indirectly wholly owned subsidiary of Progress Fuels, acquired a 50 percent interest in 11 natural gas producing wells and proven reserves of approximately 25 billion cubic feet equivalent from a privately owned company headquartered in Texas. In addition to the natural gas reserves, the transaction also included a 50 percent interest in the gas gathering systems related to these reserves. The total cash purchase price for the transaction was $46 million. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2005. In 2006, we sold our 50 percent interest in the wells, reserves and gas gathering system as part of our transaction with EXCO Resources, Inc. (See Note 3C).

5. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

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

(in millions)	Depreciable Lives	**2007**	2006
Production plant	7-43	**$13,765**	$12,685
Transmission plant	17-75	**2,684**	2,509
Distribution plant	13-55	**7,676**	7,351
General plant and other	5-35	**1,202**	1,198
Utility plant in service		**$25,327**	$23,743

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

AFUDC represents the estimated 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 8.8%, 8.7% and 5.6% in 2007, 2006 and 2005, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8%, 8.8% and 7.8% in 2007, 2006 and 2005, respectively.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4%, 2.3% and 2.2% in 2007, 2006 and 2005, respectively. The depreciation provisions related to utility plant were $560 million, $533 million and $477 million in 2007, 2006 and 2005, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 7B).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2007, 2006 and 2005 was $139 million, $140 million and $136 million, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income.

PEC's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.1% for 2007, 2006 and 2005. The depreciation provisions related to utility plant were $303 million, $294 million and $286 million in 2007, 2006 and 2005, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Note 7B) and Clean Smokestacks Act amortization (See Note 7B).

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.7%, 2.7% and 2.3% in 2007, 2006 and 2005, respectively. The depreciation provisions related to utility plant were $257 million, $239 million and $191 million in 2007, 2006 and 2005, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D) and regulatory approved expenses (See Notes 7 and 21).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the DOE and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2007, 2006 and 2005 was $110 million, $109 million and $107 million, respectively, for PEC and $29 million, $31 million and $29 million, respectively, for PEF. These costs were included in fuel used for electric generation in the Statements of Income.

B. Diversified Business Property

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

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

(in millions)	2007	2006
Equipment (3-25 years)	$6	$10
Land and mineral rights	–	1
Buildings and plants (5-40 years)	9	47
Accumulated depreciation	(9)	(50)
Diversified business property, net	$6	$8

Diversified business depreciation expense was $3 million, $2 million and $4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

C. Joint Ownership of Generating Facilities

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs (See Note 21B). Each of the Utilities' share of operating costs of the above jointly owned generating facilities is included within the corresponding line in the 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 the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $1.384 billion and $1.287 billion at December 31, 2007 and 2006, respectively. Net nuclear decommissioning trust 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 2007, 2006 and 2005. Management believes that nuclear decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 AROs, which are included in depreciation and amortization expense, were $126 million, $123 million and $168 million in 2007, 2006 and 2005, respectively.

2007

(in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$519	$270	$128
PEC	Harris	83.83%	3,175	1,581	21
PEC	Brunswick	81.67%	1,647	959	16
PEC	Roxboro Unit 4	87.06%	634	164	39
PEF	Crystal River Unit 3	91.78%	817	450	177
PEF	Intercession City Unit P11	66.67%	23	9	–

2006

(in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$517	$263	$–
PEC	Harris	83.83%	3,159	1,489	18
PEC	Brunswick	81.67%	1,632	941	15
PEC	Roxboro Unit 4	87.06%	356	163	1
PEF	Crystal River Unit 3	91.78%	811	452	76
PEF	Intercession City Unit P11	66.67%	23	7	–

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

D. Asset Retirement Obligations

At December 31, 2007 and 2006, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $150 million and $156 million, respectively. The fair value of funds set aside

During 2005, PEF performed a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study decreased the rates used to calculate cost of removal expense with a resulting decrease of approximately $55 million in 2006.

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)	2007	2006
Removal costs	$1,410	$1,341
Nonirradiated decommissioning costs	141	137
Dismantlement costs	125	124
Non-ARO cost of removal	$1,676	$1,602

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC's most recent site-specific estimates of decommissioning costs were developed in 2004, using 2004 cost factors, and are based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2004 dollars, were $569 million for Unit No. 2 at Robinson Nuclear Plant (Robinson), $418 million for Brunswick Nuclear Plant (Brunswick) Unit No. 1, $444 million for Brunswick Unit No. 2 and $775 million for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. NRC operating licenses held by PEC currently expire in July 2030, December 2034 and September 2036 for Robinson and Brunswick Units No. 2 and No. 1, respectively. The NRC operating license held by PEC for Harris currently expires in October 2026. An application to extend this license 20 years was submitted in the fourth quarter of 2006. Based on updated assumptions, in 2005 PEC further reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $14 million and $49 million, respectively.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF filed a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) with the FPSC on April 29, 2005, as part of PEF's base rate filing. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2005 dollars, is $614 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. We expect to submit an application requesting a 20-year extension of this license in the first quarter of 2009. As part of this new estimate and assumed license extension, PEF reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $36 million and $94 million, respectively. In addition, we reduced PEF-related asset retirement costs, net of accumulated depreciation, by an additional $53 million at Progress Energy. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of a previous base rate agreement, and the base rate agreement resulting from a base rate proceeding in 2005 continues that suspension. 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 filed an updated fossil dismantlement study with the FPSC on April 29, 2005, as part of its base rate filing. PEF's reserve for fossil plant dismantlement was approximately $146 million and $145 million at December 31, 2007 and 2006, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended through December 2005 under the terms of PEF's previous base rate agreement. The base rate agreement resulting from a base rate proceeding in 2005 continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants (See Note 7C).

Upon implementation of FIN 47 as of December 31, 2005, the Utilities recognized additional ARO liabilities for asbestos abatement costs (See Note 1D).

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

Our nonregulated AROs relate to our abandoned synthetic fuels operations. The related asset retirement costs, net of accumulated depreciation, totaled $1 million at December 31, 2006, and none at December 31, 2007.

The following table presents the changes to the AROs during the years ended December 31, 2007 and 2006. Revisions to prior estimates of the PEC regulated ARO are related to remeasuring the nuclear decommissioning costs of irradiated plants to take into account updated site-specific decommissioning cost studies, which are required by the NCUC every five years. Revisions to prior estimates of the PEF regulated ARO are related to the updated cost estimate for nuclear decommissioning described above.

(in millions)	Regulated	Nonregulated
Asset retirement obligations at January 1, 2006	$1,239	$–
Accretion expense	72	–
Remediation	(2)	1
Revisions to prior estimates	(6)	–
Asset retirement obligations at December 31, 2006	1,303	1
Accretion expense	**75**	**–**
Remediation	**–**	**(1)**
Asset retirement obligations at December 31, 2007	**$1,378**	**$–**

E. Insurance

The Utilities are members of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities. Under the primary program, each company is insured for $500 million at each of its respective nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $1.750 billion on each nuclear plant.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under NEIL, following a 12-week deductible period, for 52 weeks in the amount of $4 million per week at the Brunswick, Harris and Robinson plants, and $5 million per week at the Crystal River Plant. An additional 110 weeks of coverage is provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $34 million with respect to the primary coverage, $37 million with respect to the decontamination, decommissioning and excess property coverage, and $24 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $10.760 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 $100 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 $15 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 31, 2008.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.200 billion for non-certified acts, along with any amounts it recovers from reinsurance, government indemnity or other sources up to the limits for each claimant. If terrorism losses occurred beyond the one-year period, a new set of limits and resources would apply.

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

6. CURRENT ASSETS

A. Receivables

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

(in millions)	2007	2006
Trade accounts receivable	$586	$628
Unbilled accounts receivable	220	227
Notes receivable	67	57
Derivative accounts receivable	247	–
Other receivables	46	46
Allowance for doubtful receivables	(29)	(28)
Total receivables	$1,137	$930

B. Inventory

At December 31 inventory was comprised of:

(in millions)	2007	2006
Fuel for production	$455	$470
Inventory for sale	–	2
Materials and supplies	520	442
Emission allowances	19	22
Total inventory	$994	$936

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits of $65 million and $44 million at December 31, 2007 and 2006, respectively.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits of $32 million at December 31, 2007. Progress Energy did not have any long-term emission allowance amounts at December 31, 2006.

7. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As regulated entities, the Utilities are subject to the provisions of SFAS No. 71. Accordingly, the Utilities record certain assets and liabilities resulting from the effects of the ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utilities' ability to continue to meet the criteria for application of SFAS No. 71 could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS No. 71 no longer applies to a separable portion of our operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, such an event could result in an impairment of utility plant assets as determined pursuant to SFAS No. 144.

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

(in millions)	2007	2006
Deferred fuel cost – current (Note 7B)	$154	$196
Deferred fuel cost – long-term (Note 7B)	114	114
Deferred impact of ARO – PEC (Note 1D)	294	282
Income taxes recoverable through future rates (Note 14)	141	114
Loss on reacquired debt (Note 1D)	43	46
Storm deferral (Notes 7B and 7C)	22	102
Postretirement benefits (Note 16)	212	373
Derivative mark-to-market adjustment (Note 17A)	–	78
Environmental (Notes 7B, 7C and 21A)	40	72
Investment in GridSouth (Note 7D)	22	–
Other	43	50
Total long-term regulatory assets	931	1,231
Deferred fuel cost – current (Note 7C)	(154)	(63)
Deferred energy conservation cost and other current regulatory liabilities	(19)	(13)
Total current regulatory liabilities	(173)	(76)
Non-ARO cost of removal (Note 5D)	(1,676)	(1,602)
Deferred impact of ARO – PEF (Note 1D)	(226)	(221)
Net nuclear decommissioning trust unrealized gains (Note 5D)	(351)	(330)
Clean Smokestacks Act compliance (Note 7B)	–	(333)
Derivative mark-to-market adjustment (Note 17A)	(185)	–
Storm reserve (Note 7C)	(63)	(2)
Other	(38)	(55)
Total long-term regulatory liabilities	(2,539)	(2,543)
Net regulatory liabilities	$(1,627)	$(1,192)

Except for portions of deferred fuel costs and loss on reacquired debt, all regulatory assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. We anticipate recovering long-term deferred fuel costs in 2009 and loss on reacquired debt over the applicable lives of the debt. We expect to fully recover our regulatory assets and refund our regulatory liabilities through customer rates under current regulatory practice.

B. PEC Retail Rate Matters

BASE RATES

PEC's base rates are subject to the regulatory jurisdiction of the NCUC and SCPSC. In PEC's most recent rate cases in 1988, the NCUC and the SCPSC each authorized a return on equity (ROE) of 12.75 percent. In June 2002, the North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) from their North Carolina coal-fired power plants in phases by 2013. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended December 31, 2007, unless there were extraordinary events beyond the control of the utilities or unless the utilities persistently earned a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. There were no adjustments to PEC's base rates during the five-year period ended December 31, 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation.

During the rate freeze period, the legislation provided for a minimum amortization and recovery of 70 percent of the original estimated compliance costs of $813 million (or $569 million) while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. For the years ended December 31, 2007, 2006 and 2005, PEC recognized amortization of $34 million, $140 million and $147 million, respectively, and recognized $569 million in cumulative amortization through December 31, 2007.

On March 23, 2007, PEC filed a petition with the NCUC requesting that it be allowed to amortize the remaining 30 percent (or $244 million) of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, with discretion to amortize up to $174 million in either year. Additionally, among other things, PEC requested that the NCUC allow PEC to include in its rate base those eligible compliance costs exceeding the original estimated compliance costs and that PEC be allowed to accrue AFUDC on all eligible compliance costs in excess of the original estimated compliance costs. PEC also requested that any prudency review of PEC's environmental compliance costs be deferred until PEC's next ratemaking proceeding in which PEC seeks to adjust its base rates. On October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, the Carolina Utility Customers Associations (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis, with the NCUC indicating that it intended to initiate a review in 2009 to consider all reasonable alternatives and proposals related to PEC's recovery of its Clean Smokestacks Act compliance costs in excess of the original estimated costs of $813 million. Additionally, the NCUC ordered that no portion of Clean Smokestacks Act compliance costs directly assigned, allocated or otherwise attributable to another jurisdiction shall be recovered from PEC's retail North Carolina customers, even if recovery of these costs is disallowed or denied, in whole or in part, in another jurisdiction. We cannot predict the outcome of PEC's recovery of eligible compliance costs exceeding the original estimated compliance costs.

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

FUEL COST RECOVERY

On May 2, 2007, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers. PEC asked the SCPSC to approve a $12 million increase in fuel rates for under-recovered fuel costs associated with prior year settlements and to meet future expected fuel costs. On June 27, 2007, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceedings. The settlement agreement resolved all issues and provided for a $12 million increase in fuel rates. Effective July 1, 2007, residential electric bills increased by $1.83 per 1,000 kilowatt-hours (kWh), or 1.9 percent, for fuel cost recovery. At December 31, 2007, PEC's South Carolina deferred fuel balance was $21 million.

On June 8, 2007, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. PEC asked the NCUC to approve a $48 million increase in fuel rates. On September 25, 2007, the NCUC approved PEC's petition. The increase took effect October 1, 2007, and increased residential electric bills by $1.30 per 1,000 kWh, or 1.3 percent, for fuel cost recovery. This was the second increase associated with a three-year settlement approved by the NCUC in 2006. The settlement provided for an increase of $177 million effective October 1, 2006; $48 million effective October 1, 2007, as discussed above; and an additional increase of approximately $30 million in October 2008. On November 21, 2006, CUCA filed an appeal with the North Carolina Tenth District Court of Appeals of the NCUC's order approving the settlement on the grounds that the NCUC did not have the statutory authority to establish fuel rates for more than one year. On October 24, 2007, CUCA filed a motion to withdraw their appeal. On November 7, 2007, the North Carolina Tenth District Court of Appeals granted CUCA's motion. At December 31, 2007, PEC's North Carolina deferred fuel balance was $241 million, of which $114 million is expected to be collected after 2008 and has been classified as a long-term regulatory asset.

STORM COST RECOVERY

In February 2004, PEC filed with the SCPSC seeking permission to defer expenses incurred from the first quarter 2004 winter storm. In September 2004, the SCPSC approved PEC's request to defer the costs and amortize them ratably over five years beginning in January 2005. Approximately $9 million related to storm costs was deferred in 2004. For the years ended December 31, 2007, 2006 and 2005, PEC recognized $2 million of South Carolina storm amortization.

In October 2003, PEC filed with the NCUC seeking permission to defer approximately $24 million of expenses incurred from Hurricane Isabel and the February 2003 winter storms. In December 2003, the NCUC approved PEC's request to defer the costs associated with Hurricane Isabel and the February 2003 winter storms and amortize them over a period of five years. For the years ended December 31, 2007, 2006 and 2005, PEC recognized $5 million of North Carolina storm amortization.

OTHER MATTERS

PEC filed petitions on September 14, 2006, and September 22, 2006, with the SCPSC and NCUC, respectively, seeking authorization to defer and amortize the respective jurisdictional portion of $18 million of previously recorded operation and maintenance (O&M) expense relating to certain environmental remediation sites (See Note 21A). On October 11, 2006, the SCPSC granted PEC's petition to defer its jurisdictional amount, totaling $3 million, and amortize it over a five-year period beginning January 1, 2007. On October 19, 2006, the NCUC granted PEC's petition to defer its jurisdictional amount, totaling $15 million, and amortize it over a five-year period. However, the NCUC order directed that amortization begin in 2006, with an amortization expense of $3 million. As a result, during the fourth quarter of 2006, PEC reversed $18 million of O&M expense, established a regulatory asset and recorded $3 million of amortization expense. During the year ended December 31, 2007, PEC recorded $3 million of amortization expense. Additionally, PEC reduced the regulatory asset by $2 million during the year ended December 31, 2007, based on newly available data regarding certain remediation sites and insurance proceeds (See Note 21A).

The NCUC and SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The aggregate minimum and maximum amounts of cost recovery are $530 million and $750 million, respectively, 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 $37 million in 2007. No additional depreciation expense from accelerated cost recovery was recorded in 2006 or 2005. Through December 31, 2007, PEC recorded total accelerated depreciation of $440 million, of which $363 million was recorded for the North Carolina jurisdiction and $77 million was recorded for the South Carolina jurisdiction.

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. Among other provisions, the law allows the utility to recover the costs of new demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs that are intended to produce future benefits and authorizes the NCUC to approve other forms of financial incentives to the utility for DSM and energy-efficiency programs. DSM programs include any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control and interruptible load. PEC has begun implementing a series of DSM and energy-efficiency programs and deferred $2 million of implementation and program costs through December 31, 2007, for future recovery.

PEC filed a petition on November 30, 2007, with the SCPSC seeking authorization to create a deferred account for DSM and energy-efficiency expenses. On December 21, 2007, the SCPSC issued an order granting PEC's petition. As a result, PEC has deferred an immaterial amount of implementation and program costs through December 31, 2007, for future recovery in the South Carolina jurisdiction. PEC anticipates applying for a DSM and energy-efficiency clause to recover the costs of these programs in 2008. We cannot predict the outcome of this matter.

C. PEF Retail Rate Matters

BASE RATE AGREEMENT

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009, with PEF having sole option to extend the agreement through the last billing cycle of June 2010 pursuant to the agreement. In accordance with the base rate agreement and as modified by a stipulation and settlement agreement approved by the FPSC on October 23, 2007, base rates were adjusted in January 2008 due to specified generation facilities placed in service in 2007. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006 whereby PEF will refund two-thirds of retail base revenues between the specified threshold and specified cap and 100 percent of revenues above the specified cap. However, PEF's retail base revenues did not exceed the specified 2007 threshold of $1.537 billion and thus no revenues were subject to revenue sharing. Both the 2007 base threshold of $1.537 billion and the 2007 cap of $1.588 billion will be adjusted annually for rolling average 10-year retail kWh sales growth. PEF's 2006 retail base rates did not exceed the threshold and no revenues were subject to the revenue sharing provisions. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the recovery of post-9/11 security costs through the capacity clause and the carrying costs of coal inventory in transit and coal procurement costs through the fuel clause. Under the settlement agreement, PEF is authorized to include an adjustment to increase common equity for the impact of Standard & Poor's Rating Services' (S&P's) imputed off-balance sheet debt for future capacity payments to qualifying facilities (QFs) and other entities under long-term purchase power agreements. This adjusted capital structure will be used for surveillance reporting with the FPSC and pass-through clause return calculations. PEF will use an authorized 11.75 percent ROE for cost-recovery clauses and AFUDC. In addition, PEF's adjusted equity ratio will be capped at 57.83 percent as calculated on a financial capital structure that includes the adjustment for the S&P imputed off-balance sheet debt. If PEF's regulatory ROE falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

PASS-THROUGH CLAUSE COST RECOVERY

On September 4, 2007, PEF filed a request with the FPSC seeking approval of a cost adjustment to reflect a projected over-collection of fuel costs in 2007, declining projected fuel costs for 2008 and other recovery clause factors. PEF asked the FPSC to approve a $163 million, or 4.53 percent, decrease in rates effective January 1, 2008. This cost adjustment would decrease residential bills by $5.00 for the first 1,000 kWh. As discussed above, residential base rates increased due to specified generation facilities placed in service in 2007 by $2.73 for the first 1,000 kWh effective January 1, 2008. After considering the net effect of the base rate increase and the proposed fuel cost adjustment, 2008 residential bills would decrease by a net amount of $2.27 for the first 1,000 kWh. The FPSC approved the cost-recovery rates for 2008 in an order dated January 8, 2008. At December 31, 2007, PEF's current regulatory liabilities totaled $173 million, which were comprised of over-recovered fuel and capacity costs of $140 million, accrued disallowed fuel costs of $14 million, over-recovered conservation costs of $14 million and over-recovered environmental compliance of $5 million.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and SO_2 allowance costs during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. The OPC claimed that although Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) were designed to burn a blend of coals, PEF failed to act to lower ratepayers' costs by purchasing the most economical blends of coal. During the period specified in the petition, PEF's costs recovered through fuel recovery clauses were annually reviewed for prudence and approval by the FPSC. On July 31, 2007, the FPSC heard this matter. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the 4-1 majority found that PEF had not been prudent in purchasing a portion of its coal requirements during the period from 2003 to 2005. Accordingly, the FPSC ordered PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. For the year ended December 31, 2007, PEF recorded a pre-tax other operating expense of $12 million, interest expense of $2 million and an associated $14 million regulatory liability included within PEF's deferred fuel cost at December 31, 2007. On October 25, 2007, the OPC requested the FPSC to reconsider its October 10, 2007 order asserting that the FPSC erred in not ordering a larger refund. PEF filed its opposition to the OPC's request on November 1, 2007. On February 12, 2008, the FPSC denied the OPC's request for reconsideration. PEF is also evaluating its options, including an appeal to the Florida Supreme Court of the FPSC's October 10, 2007 order. We cannot predict the outcome of this matter. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. On October 4, 2007, PEF filed a motion to establish a separate docket on the prudence of its coal purchases for CR4 and CR5 for the years 2006 and 2007. On October 17, 2007, the FPSC granted that motion. The OPC filed testimony in support of its position to require PEF to refund at least $14 million for alleged excessive fuel recovery charges for 2006 coal purchases. PEF believes its coal procurement practices have been prudent. We cannot predict the outcome of this matter.

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate CR3, bid rule exemption and recovery of the revenue requirements of the uprate through PEF's fuel recovery clause. To the extent the expenditures are prudently incurred, PEF's investment in the CR3 uprate is eligible for recovery through base rates. PEF's petition would allow for more prompt recovery. The multi-stage uprate will increase CR3's gross output by approximately 180 MW by 2012. PEF received NRC approval for a license amendment and implemented the first stage's design modification on January 31, 2008, and will apply for the required license amendment for the third stage's design modification. The petition filed with the FPSC included estimated project costs of approximately $382 million. These cost estimates may continue to change depending upon the results of more detailed engineering and development work and increased material, labor and equipment costs. On February 8, 2007, the FPSC issued an order approving the need certification petition and bid rule exemption. The request for recovery through PEF's fuel recovery clause was transferred to a separate docket filed on January 16, 2007. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. On March 27, 2007, the FPSC denied the motion to abate and directed the staff of the FPSC to conduct a hearing to determine whether the revenue requirements of the uprate should be recovered through the fuel recovery clause. On May 4, 2007, PEF filed amended testimony clarifying the scope of the project. The FPSC held a hearing on this matter on August 7 and 8, 2007. The staff of the FPSC recommended that PEF be allowed to recover prudent and reasonable costs of Phase 1, estimated at $6 million, through the fuel clause. The staff of the FPSC recommended that the costs of all other phases, estimated at $376 million, be considered in a base rate proceeding. On October 19, 2007, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. On November 21, 2007, PEF filed a petition with the FPSC seeking cost recovery under Florida's comprehensive energy bill enacted in 2006, and the FPSC's new nuclear cost-recovery rule. On February 13, 2008, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. PEF will proceed with cost recovery under Florida's comprehensive energy bill and the FPSC's nuclear cost-recovery rule based on the regulatory precedence established by a FPSC order to an unaffiliated Florida utility for a nuclear uprate project. We cannot predict the outcome of this matter.

STORM COST RECOVERY

On July 14, 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power associated with the four hurricanes in 2004. The ruling allowed PEF to include a charge of approximately $3.27 on the average residential monthly customer bill of 1,000 kWh beginning August 1, 2005. The ruling by the FPSC approved the majority of PEF's requests with two exceptions: the reclassification of $8 million of previously deferred costs to utility plant and the reclassification of $17 million of previously deferred costs as O&M expense, which was expensed in the second quarter of 2005. The amount included in the original November 2004 petition requesting recovery of $252 million was an estimate. On September 12, 2005, PEF filed a true-up to the original amount comprised primarily of an additional $19 million of costs partially offset by $6 million of adjustments resulting from allocating a higher portion of the costs to the wholesale jurisdiction and refining the FPSC adjustments. On November 9, 2005, the recovery of this difference was administratively approved by the FPSC, subject to audit by the FPSC staff. The net impact was included in customer bills beginning January 1, 2006. In 2007, 2006 and 2005, PEF recorded amortization of $75 million, $122 million and $50 million, respectively, associated with the recovery of these storm costs. The retail portion of storm restoration costs were fully recovered at December 31, 2007.

On April 25, 2006, PEF entered into a settlement agreement with certain intervenors in its storm cost-recovery docket that would allow PEF to extend its then-current two-year storm surcharge, which equals approximately

$3.61 on the average residential monthly customer bill of 1,000 kWh, for an additional 12-month period to replenish its storm reserve. The requested extension, which began August 2007, is expected to replenish the existing storm reserve by an estimated $126 million. During the third quarter of 2006, PEF and the intervenors modified the settlement agreement such that in the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence. On August 29, 2006, the FPSC approved the settlement agreement as modified. Through December 31, 2007, PEF had recorded an additional $55 million of storm reserve from the extension of the storm surcharge. At December 31, 2007, PEF's storm reserve totaled $63 million.

FRANCHISE MATTERS

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

OTHER MATTERS

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

D. Regional Transmission Organizations

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

On November 16, 2007, PEC petitioned the NCUC to allow it to establish a regulatory asset for PEC's development costs of GridSouth pending disposition in a general rate proceeding. On January 14, 2008, the NCUC issued an order requesting interested parties to file comments regarding PEC's petition on or before January 28, 2008. On February 11, 2008, PEC filed response comments. On December 20, 2007, the NCUC issued an order for one of the other GridSouth partners. As part of that order, the NCUC ruled that the utility's GridSouth development costs should be amortized and recovered over a 10-year period beginning June 2002. Until the NCUC rules upon PEC's petition, PEC will apply the same accounting treatment to its GridSouth development costs. Consequently, in December 2007, PEC recorded an $11 million charge to amortization expense to reduce the North Carolina portion of development costs, which is included in depreciation and amortization on the Consolidated Statements of Income. PEC's recorded investment in GridSouth totaled $22 million and $33 million at December 31, 2007 and 2006. PEC expects to recover its GridSouth development costs based on precedent regulatory proceedings; in 2007, PEC reclassified its investment in GridSouth from other assets and deferred debits to regulatory assets on the Consolidated Balance Sheets. We cannot predict the outcome of this matter.

PEF was one of three major investor-owned Florida utilities that formed the GridFlorida RTO in 2000. A cost-benefit study conducted during 2005 concluded that the GridFlorida RTO was not cost effective for FPSC jurisdictional customers and shifted benefits to nonjurisdictional customers. In light of these findings, during 2006 the FPSC and the FERC closed their respective docketed proceedings and GridFlorida was dissolved. PEF fully recovered its development costs in GridFlorida from retail ratepayers through base rates.

E. Nuclear License Renewals

The NRC operating license for Robinson expires in 2030 and the licenses for Brunswick expire in 2036 for Unit No. 1 and 2034 for Unit No. 2. On November 14, 2006, PEC filed an application for a 20-year extension from the NRC on the operating license for Harris, which would extend the operating license through 2046, if approved. PEC anticipates a decision from the NRC in 2008. The NRC operating license held by PEF for CR3 currently expires in December 2016. PEF expects to submit an application requesting a 20-year extension of this license in the first quarter of 2009.

8. GOODWILL AND INTANGIBLE ASSETS

We perform annual goodwill impairment tests in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Goodwill was tested for impairment for both the PEC and PEF segments in the second quarters of 2007 and 2006; each test indicated no impairment. Under SFAS No. 142, all goodwill is assigned to our reporting units that are expected to benefit from the synergies of the business combination.

Goodwill impairment tests were performed at our CCO-Georgia Operations reporting unit level, which was comprised of four nonregulated generating plants (Georgia Operations). As a result of our evaluation of certain business opportunities that impacted the future cash flows of our Georgia Operations, we performed the annual goodwill impairment test during the first quarter of 2006. We estimated the fair value of that reporting unit using the expected present value of future cash flows. As a result of that test, we recognized a pre-tax goodwill impairment charge of $64 million ($39 million after-tax) during the first quarter of 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income (See Note 3A).

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding future synthetic fuels production. With the idling of these facilities, we performed an evaluation of the intangible assets, which were comprised primarily of capitalized acquisition costs (See Note 9 for impairment of related long-lived assets). The impairment test considered numerous factors including, among other things, continued high oil prices and the then-current idled state of our synthetic fuels facilities. We estimated the fair value using the expected present value of future cash flows. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $27 million ($17 million after-tax) during the quarter ended June 30, 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. This charge represented the entirety of the synthetic fuels intangible assets; these assets had been reported within our former Coal and Synthetic Fuels segment (See Note 3B).

9. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. In 2006, we recorded pre-tax long-lived asset and investment impairments and other charges of $65 million, of which $64 million has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income.

A. Long-Lived Assets

Due to rising current and future oil prices, in the third and fourth quarters of 2005 we tested our synthetic fuels plant assets for impairment. These tests indicated that the assets were recoverable and no impairment charge was recorded. See Note 22D for additional information.

Concurrent with the synthetic fuels intangibles impairment evaluation discussed in Note 8, we also performed an impairment evaluation of related long-lived assets during the second quarter of 2006. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $64 million ($38 million after-tax) during the quarter ended June 30, 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income, as discussed in Note 3B. This charge represents the entirety of the asset carrying value of our synthetic fuels manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities are located. These assets had been reported within our former Coal and Synthetic Fuels segment. There were no impairments of long-lived assets in 2007.

B. Investments

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

We continually review PEC's affordable housing investment (AHI) portfolio for impairment. There were no other-than-temporary impairments in 2007. As a result of various factors, including continued operating losses of the AHI portfolio and management issues arising at certain properties within the AHI portfolio, we recorded impairment charges of $1 million on a pre-tax basis in both 2006 and 2005.

10. EQUITY

A. Common Stock

At December 31, 2007 and 2006, we had 500 million shares of common stock authorized under our charter, of which 260 million shares and 256 million shares, respectively, were outstanding. During 2007, 2006 and 2005, respectively, we issued approximately 3.4 million, 4.2 million and 4.8 million shares of common stock, resulting in approximately $151 million, $185 million and $208 million in proceeds. Included in these amounts for 2007, 2006 and 2005, respectively, were approximately 1.0 million, 1.6 million and 4.6 million shares for proceeds of approximately $46 million, $70 million and $199 million, to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan.

At December 31, 2007 and 2006, we had approximately 50 million shares and 54 million shares, respectively, of common stock authorized by the board of directors that remained unissued and reserved, primarily to satisfy the requirements of our stock plans. In 2002, the board of directors authorized meeting the requirements of the 401(k) and the Investor Plus Stock Purchase Plan with original issue shares. We continue to meet the requirements of the restricted stock plan with issued and outstanding shares.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2007, there were no significant restrictions on the use of retained earnings (See Note 12).

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. At December 31, 2007 and 2006, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes.

There were 1.7 million and 2.3 million ESOP suspense shares at December 31, 2007 and 2006, respectively, with a fair value of $82 million and $112 million, respectively. ESOP shares allocated to plan participants totaled 10.6 million and 10.9 million at December 31, 2007 and 2006, respectively. Our matching and incentive goal compensation cost under the 401(k) is determined based on matching percentages and incentive goal attainment as defined in the plan. Such compensation cost is allocated to participants' accounts in the form of Progress Energy common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. We currently meet common stock share needs with open market purchases, with shares released from the ESOP suspense account and with newly issued shares. Costs for incentive goal compensation are accrued during the fiscal year and typically paid in shares in the following year, while costs for the matching component are typically met with shares in the same year incurred. Matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately \$23 million, \$14 million and \$18 million for the years ended December 31, 2007, 2006 and 2005, respectively. Total matching and incentive costs were approximately \$30 million, \$23 million and \$30 million for the years ended December 31, 2007, 2006 and 2005, respectively. We have a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

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

STOCK OPTIONS

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

A summary of the status of our stock options at December 31, 2007, and changes during the year then ended, is presented below:

(option quantities in millions)	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	4.0	\$43.70
Canceled	–	45.55
Exercised	(2.3)	43.47
Options outstanding, December 31	1.7	43.99
Options exercisable, December 31	1.7	43.99

The options outstanding and exercisable at December 31, 2007, had a weighted-average remaining contractual life of 5.0 years and an aggregate intrinsic value of \$8 million. Total intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005, respectively, was \$17 million, \$10 million and less than \$1 million.

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

As of December 31, 2006, all options were fully vested; therefore, no compensation expense was recognized in 2007. Stock option expense totaling \$2 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of \$1 million. No compensation cost related to stock options was capitalized during the year. Stock option expense totaling \$3 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of \$1 million. No compensation cost related to stock options was capitalized during the year.

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

(in millions, except per share data)	2005
Net income, as reported	$697
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	2
Pro forma net income	$695
Earnings per share	
Basic – as reported	$2.82
Basic – pro forma	2.81
Diluted – as reported	2.82
Diluted – pro forma	2.81

Cash received from the exercise of stock options totaled $105 million, $115 million and $8 million, respectively, during the years ended December 31, 2007, 2006 and 2005. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2007 and 2006, was $6 million and $4 million, respectively. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2005, was not significant.

OTHER STOCK-BASED COMPENSATION PLANS

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

We granted cash-settled PSSP awards prior to 2005. Since 2005, we have been granting stock-settled PSSP awards. Under the terms of the PSSP, our officers and key employees are granted a target number of performance shares on an annual basis that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of Progress Energy common stock, and dividend equivalents are accrued on, and reinvested in, additional performance shares. Prior to 2007, shares issued under the PSSP (both cash-settled and stock-settled) had two equally weighted performance measures, both of which were based on our results as compared to a peer group of utilities. In 2007, the PSSP was redesigned, and shares issued under the revised plan use one performance measure. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. For cash-settled awards, compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated to reflect factors such as changes in stock price and the status of performance measures. The stock-settled PSSP is similar to the cash-settled PSSP, except that we distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with subsequent adjustments made to reflect the status of the performance measure. Compensation expense for all awards is reduced by estimated forfeitures. PSSP cash-settled liabilities totaling $3 million, $4 million and $5 million were paid in the years ended December 31, 2007, 2006 and 2005, respectively. A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2007, and changes during the year then ended is presented below:

	Number of Stock-Settled Performance Shares[a]	Weighted-Average Grant Date Fair Value
Beginning balance	1,044,583	$44.26
Granted	892,410	50.70
Paid[b]	(190,567)	50.70
Forfeited	(116,431)	44.84
Ending balance	1,629,995	$44.97

[a] Amounts reflect target shares to be issued. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.
[b] Shares paid include only target shares as originally granted. Additional shares of 106,478 were issued and paid due to exceeding established performance thresholds and due to dividends earned.

For the years ended December 31, 2006 and 2005, the weighted-average grant date fair value of stock-settled performance shares granted was $44.27 and $44.24, respectively.

The Restricted Stock Award (RSA) program allows us to grant shares of restricted common stock to our officers and key employees. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. Restricted shares are not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. A summary of the status of the nonvested restricted stock shares at December 31, 2007, and changes during the year then ended, is presented below.

For the years ended December 31, 2006 and 2005, the weighted-average grant date fair value of restricted stock granted was $44.51 and $42.56, respectively.

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	604,238	$43.82
Granted	7,000	49.54
Vested	(303,935)	44.08
Forfeited	(38,668)	43.16
Ending balance	268,635	$43.77

The total fair value of restricted stock awards vested during the years ended December 31, 2007, 2006 and 2005 was $13 million, $4 million and $7 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million during the years ended December 31, 2006 and 2005, respectively. Cash expended to purchase shares for 2007 was not significant due to the curtailment of the RSA program and the rollout of the new restricted stock unit (RSU) program.

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

	Number of Restricted Units	Weighted-Average Grant Date Fair Value
Beginning balance	–	$–
Granted	913,282	50.33
Vested	(49,430)	50.70
Forfeited	(39,394)	50.70
Ending balance	824,458	$50.29

The total fair value of RSUs vested during the year ended December 31, 2007, was $3 million. There were no expenditures to purchase stock to satisfy RSU plan obligations in 2007.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $70 million for the year ended December 31, 2007, with a recognized tax benefit of $27 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $25 million with a recognized tax benefit of $10 million and $10 million, with a recognized tax benefit of $4 million, for the years ended December 31, 2006 and 2005, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2007, there was $51 million of total unrecognized compensation cost related to nonvested other stock-based compensation plan awards, which is expected to be recognized over a weighted-average period of 1.8 years.

C. Earnings per Common Share

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

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

(in millions)	**2007**	2006	2005
Weighted-average common shares – basic	**256.1**	250.4	246.6
Net effect of dilutive stock-based compensation plans	**0.6**	0.4	0.4
Weighted-average shares – fully diluted	**256.7**	250.8	247.0

There were no adjustments to net income or to income from continuing operations between the calculations of basic and fully diluted earnings per common share. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. The weighted-average shares totaled 1.8 million, 2.4 million and 3.0 million for the years ended December 31, 2007, 2006 and 2005, respectively. There were 0.1 million, 1.8 million and 2.9 million stock options outstanding at December 31, 2007, 2006 and 2005, 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)	**2007**	2006
Loss on cash flow hedges	**$(23)**	$(14)
Pension and other postretirement benefits	**(13)**	(39)
Other	**2**	4
Total accumulated other comprehensive loss	**$(34)**	$(49)

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

All of our preferred stock was issued by our subsidiaries and was not subject to mandatory redemption. At December 31, 2007 and 2006, 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			
$5 Preferred		236,997	$110.00	$24
Cumulative, no par value Serial Preferred Stock	20,000,000			
$4.20 Serial Preferred		100,000	102.00	10
$5.44 Serial Preferred		249,850	101.00	25
Cumulative, no par value Preferred Stock A	5,000,000	–	–	–
No par value Preference Stock	10,000,000	–	–	–
Total PEC				59
PEF				
Cumulative, $100 par value Preferred Stock	4,000,000			
4.00% $100 par value Preferred		39,980	104.25	4
4.40% $100 par value Preferred		75,000	102.00	8
4.58% $100 par value Preferred		99,990	101.00	10
4.60% $100 par value Preferred		39,997	103.25	4
4.75% $100 par value Preferred		80,000	102.00	8
Cumulative, no par value Preferred Stock	5,000,000	–	–	–
$100 par value Preference Stock	1,000,000	–	–	–
Total PEF				34
Total preferred stock of subsidiaries				$93

12. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2007):

(in millions)		2007	2006
Progress Energy, Inc.			
Senior unsecured notes, maturing 2010-2031	6.98%	$2,600	$2,600
Unamortized fair value hedge gain, net		–	(1)
Unamortized premium and discount, net		(3)	(18)
Long-term debt, net		2,597	2,581
PEC			
First mortgage bonds, maturing 2009-2035	5.65%	2,000	2,200
Pollution control obligations, maturing 2017-2024	4.57%	669	669
Senior unsecured notes, maturing 2012	6.50%	500	500
Medium-term notes, maturing 2008	6.65%	300	300
Miscellaneous notes		22	22
Unamortized premium and discount, net		(8)	(21)
Current portion of long-term debt		(300)	(200)
Long-term debt, net		3,183	3,470
PEF			
First mortgage bonds, maturing 2008-2037	5.64%	2,380	1,630
Pollution control obligations, maturing 2018-2027	4.32%	241	241
Senior unsecured notes, maturing 2008	5.27%	450	450
Medium-term notes, maturing 2008-2028	6.75%	152	241
Unamortized premium and discount, net		(5)	(5)
Current portion of long-term debt		(532)	(89)
Long-term debt, net		2,686	2,468
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	309	309
Unamortized premium and discount, net		(38)	(38)
Long-term debt, net		271	271
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2008	6.46%	45	80
Current portion of long-term debt		(45)	(35)
Long-term debt, net		–	45
Progress Energy consolidated long-term debt, net		$8,737	$8,835

On September 18, 2007, PEF issued $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. The proceeds were used to repay PEF's utility money pool borrowings and the remainder was placed in temporary investments for general corporate use as needed.

At December 31, 2007 and 2006, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2007 and 2006, we had no outstanding borrowings under our credit facilities. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following table summarizes our revolving credit agreements (RCAs) and available capacity at December 31, 2007:

(in millions)	Description	Total	Outstanding	Reserved[(a)]	Available
Progress Energy, Inc.	Five-year (expiring 5/3/11)	$1,130	$–	$220	$910
PEC	Five-year (expiring 6/28/10)	450	–	–	450
PEF	Five-year (expiring 3/28/10)	450	–	–	450
Total credit facilities		$2,030	$–	$220	$1,810

[(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, 2007, Progress Energy, Inc. had a total amount of $19 million of letters of credit issued, which were supported by the RCA.

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

Our outstanding commercial paper and other short-term debt and related weighted-average interest rate at December 31, 2007, was $201 million and 5.48%, respectively.

We had no commercial paper outstanding or other short-term debt at December 31, 2006.

The following table presents the aggregate maturities of long-term debt at December 31, 2007:

(in millions)	
2008	$877
2009	400
2010	406
2011	1,000
2012	950
Thereafter	6,035
Total	$9,668

B. Covenants and Default Provisions

FINANCIAL COVENANTS

Progress Energy, Inc.'s, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2007, the maximum and calculated ratios, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[(a)]
Progress Energy, Inc.	68%	54.4%
PEC	65%	48.8%
PEF	65%	53.2%

[(a)] Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees that are 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 Progress Energy, Inc. and $35 million each for PEC and PEF. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of their respective cross-default threshold, the lenders of that credit facility could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. Progress Energy, Inc.'s cross-default provision can be triggered by Progress Energy, Inc. and its significant subsidiaries, as defined in the credit agreement, (i.e., PEC, Florida Progress, PEF, Progress Capital Holdings, Inc. and PVI). PEC's and PEF's cross-default provisions can only be triggered by defaults of indebtedness by PEC and its subsidiaries and PEF, respectively, not each other or other affiliates of PEC and PEF.

Additionally, certain of Progress Energy, Inc.'s long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of Progress Energy, Inc., primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $2.6 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither Progress Energy, Inc.'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, 2007, Progress Energy, Inc. had no shares of preferred stock outstanding. Certain documents restrict the payment of dividends by Progress Energy, Inc.'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, 2007, 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 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, 2007, PEC's common stock equity was approximately 53.8 percent of total capitalization. At December 31, 2007, 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, 2007, 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 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, 2007, PEF's common stock equity was approximately 52.5 percent of total capitalization. At December 31, 2007, 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, 2007, PEC and PEF had a total of $2.669 billion and $2.621 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.

13. INVESTMENTS AND FAIR VALUE OF FINANCIAL INSTRUMENTS

A. Investments

At December 31, 2007 and 2006, 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)	**2007**	2006
Nuclear decommissioning trust (See Note 5D)	**$1,384**	$1,287
Investments in equity securities[a]	**–**	5
Equity method investments[b]	**23**	24
Cost investments[c]	**8**	8
Benefit investment trusts[d]	**82**	80
Company-owned life insurance[d]	**168**	161
Marketable debt securities[e]	**1**	71
Total	**$1,666**	$1,636

(a) Certain investments in equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115 (See Note 1). These investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

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

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

(d) Investments in company-owned life insurance and other benefit plan assets are included in miscellaneous other property and investments in the Consolidated Balance Sheets and approximate fair value due to the short maturity of the instruments.

(e) We actively invest available cash balances in various financial instruments, such as tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through arrangements with banks that provide daily and weekly liquidity and 7-, 28- and 35-day auctions that allow for the redemption of the investment at its face amount plus earned income. As we intend to sell these instruments within one year or less, generally within 30 days, from the balance sheet date, they are classified as short-term investments.

B. Fair Value of Financial Instruments

DEBT

The carrying amount of our long-term debt, including current maturities, was $9.614 billion and $9.159 billion at December 31, 2007 and 2006, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $9.897 billion and $9.543 billion at December 31, 2007 and 2006, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115. These investments include investments held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning nuclear plants (See Note 5D). These nuclear decommissioning trust funds are primarily invested in stocks, bonds and cash equivalents that are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust funds, we hold other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the Consolidated Balance Sheets at amounts that approximate fair value. Our available-for-sale securities at December 31, 2007 and 2006 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2007 *(in millions)*	**Book Value**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$465**	**$354**	**$819**
Debt securities	**574**	**11**	**585**
Cash equivalents	**18**	**–**	**18**
Total	**$1,057**	**$365**	**$1,422**
2006 *(in millions)*	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$428	$324	$752
Debt securities	606	13	619
Cash equivalents	19	–	19
Total	$1,053	$337	$1,390

At December 31, 2007, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$8
Due after one through five years	145
Due after five through 10 years	198
Due after 10 years	234
Total	$585

Selected information about our sales of available-for-sale securities during the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2007**	2006	2005
Proceeds	**$1,334**	$2,547	$3,755
Realized gains	**35**	33	26
Realized losses	**37**	24	31

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Therefore, we consider available-for-sale securities in our nuclear decommissioning trust funds to be impaired if they are in a loss position. These impairments along with unrealized gains are included in our regulatory liabilities (See Note 7A) and have no earnings impact. Some of our benefit investment trusts are also managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2007 and 2006 for investments in these trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2007 and 2006, our other securities had no investments in a continuous loss position for greater than 12 months.

14. INCOME TAXES

We provide deferred income taxes for temporary differences. These occur when there are differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes under SFAS No. 109 is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders. 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)	**2007**	2006
Deferred income tax assets		
Asset retirement obligation liability	**$146**	$141
Compensation accruals	**101**	86
Deferred revenue	**–**	28
Derivative instruments	**–**	42
Environmental remediation liability	**32**	36
Income taxes refundable through future rates	**317**	216
Investments	**–**	28
Pension and other postretirement benefits	**306**	364
Unbilled revenue	**41**	36
Other	**122**	103
Federal income tax credit carry forward	**836**	851
State net operating loss carry forward (net of federal expense)	**87**	54
Valuation allowance	**(79)**	(71)
Total deferred income tax assets	**1,909**	1,914
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,482)**	(1,379)
Deferred fuel recovery	**(64)**	(60)
Deferred storm costs	**(6)**	(51)
Derivative instruments	**(59)**	–
Income taxes recoverable through future rates	**(384)**	(436)
Investments	**(25)**	–
Prepaid pension costs	**(18)**	–
Other	**(50)**	(66)
Total deferred income tax liabilities	**(2,088)**	(1,992)
Total net deferred income tax liabilities	**$(179)**	$(78)

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

(in millions)	**2007**	2006
Current deferred income tax assets	**$27**	$142
Noncurrent deferred income tax assets, included in other assets and deferred debits	**65**	17
Current deferred income tax liabilities, included in other current liabilities	**(5)**	–
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(266)**	(237)
Total net deferred income tax liabilities	**$(179)**	$(78)

At December 31, 2007, the federal income tax credit carry forward includes $772 million of alternative minimum tax credits that do not expire and $64 million of general business credits that will expire during the period 2020 through 2027.

At December 31, 2007, we had gross state net operating loss carry forwards of $1.9 billion that will expire during the period 2008 through 2026.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We established additional valuation allowances of $8 million during 2007. We believe it is more likely than not that the results of future operations will generate sufficient taxable income to allow for the utilization of the remaining deferred tax assets.

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

	2007	2006	2005
Effective income tax rate	32.3%	37.5%	36.1%
State income taxes, net of federal benefit	(2.8)	(3.5)	(3.5)
Investment tax credit amortization	1.1	1.3	1.6
Employee stock ownership plan dividends	1.1	1.3	1.5
Domestic manufacturing deduction	1.0	0.4	1.0
Other differences, net	2.3	(2.0)	(1.7)
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)		2007	2006	2005
Current	– federal	$285	$394	$441
	– state	36	70	74
Deferred	– federal	13	(94)	(173)
	– state	11	(17)	(31)
State net operating loss carry forward		1	(2)	–
Investment tax credit		(12)	(12)	(13)
Total income tax expense		$334	$339	$298

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

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2007 or 2006.
- Taxes related to discontinued operations recorded net of tax for 2007, 2006 and 2005, which are presented separately in Notes 3A through 3H.
- Taxes related to other comprehensive income recorded net of tax for 2007, 2006 and 2005, which are presented separately in the Consolidated Statements of Comprehensive Income.
- Current tax benefit of $6 million, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $3 million, which was recorded in common stock during 2006, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $2 million, which was recorded in common stock during 2005, related to excess tax deductions resulting from vesting of restricted stock awards and exercises of nonqualified stock options pursuant to the terms of our EIP.

In July 2006, the FASB issued FIN 48, which clarifies the accounting for income taxes 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 for the application of FIN 48; 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. We adopted the provisions of FIN 48 on January 1, 2007, which was accounted for as a $2 million reduction of the January 1, 2007, balance of retained earnings and a $4 million increase in regulatory assets. Including the cumulative effect impact, our liability for unrecognized tax benefits at January 1, 2007, was $126 million. Of the total amount of unrecognized tax benefits at January 1, 2007, $24 million would have affected the effective tax rate for income from continuing operations, if recognized. At December 31, 2007, our liability for unrecognized tax benefits decreased to $93 million and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations decreased to $10 million. A reconciliation of the 2007 beginning and ending balances for unrecognized tax benefits is as follows:

(in millions)	
Unrecognized tax benefits at January 1, 2007	$126
Gross amounts of increases as a result of tax positions taken in a prior period	32
Gross amounts of decreases as a result of tax positions taken in a prior period	(41)
Gross amounts of increases as a result of tax positions taken in the current period	22
Gross amounts of decreases as a result of tax positions taken in the current period	(32)
Amounts of net decreases relating to settlements with taxing authorities	(14)
Reductions as a result of a lapse of the applicable statute of limitations	–
Unrecognized tax benefits at December 31, 2007	$93

At December 31, 2006 and 2005, we had recorded $76 million and $115 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Consolidated Balance Sheets.

Prior to the adoption of FIN 48, we accounted for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2006 and 2005, we had recorded $27 million and $60 million, respectively, of tax contingency reserves under SFAS No. 5, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

We and our subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state jurisdictions. During 2007, we closed federal tax years 1998 to 2003. Our open federal tax years are from 2004 forward and our open state tax years in our major jurisdictions are generally from 1992 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when those examinations will be completed. We are not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2008.

We include interest expense related to unrecognized tax benefits in interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2007, the interest expense related to unrecognized tax benefits was $1 million, net, of which a $15 million expense component was deferred as a regulatory asset by PEF and not recognized in our Consolidated Statement of Operations. During 2007 there were no penalties related to unrecognized tax benefits. As of January 1, 2007, we had accrued $24 million for interest and penalties. As of December 31, 2007, we have accrued $23 million for interest and penalties, which are included in 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 contingent value obligations (CVOs). Each CVO represents the right of the holder to receive contingent payments based on the performance of four Earthco 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. We will make deposits into a CVO trust for estimated contingent payments due to CVO holders based on the results of operations and the utilization of tax credits. Monies held in the trust are generally not payable to the CVO holders until the completion of income tax audits. The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income (See Note 20). At December 31, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively.

During 2007, a $5 million deposit was made into a CVO trust for the net after-tax cash flows generated by the four Earthco synthetic fuels facilities in 2004. Deposits into the trust will be classified as a restricted cash asset until the applicable tax years are closed, at which time a payment will be disbursed to the CVO holders. Future payments will include principal and interest earned during the investment period net of expenses deducted. The interest earned on the payment held in trust for 2007 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheet at December 31, 2007.

16. BENEFIT PLANS

A. Postretirement Benefits

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

COSTS OF BENEFIT PLANS

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

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

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

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2007	2006	2005	2007	2006	2005
Service cost	$46	$45	$47	$7	$9	$9
Interest cost	123	117	117	32	33	33
Expected return on plan assets	(155)	(148)	(147)	(6)	(6)	(5)
Amortization of actuarial loss[a]	15	18	21	2	4	6
Other amortization, net [a]	2	–	–	5	5	5
Net periodic cost	$31	$32	$38	$40	$45	$48

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

In addition to the net periodic cost reflected above, in 2005, we recorded costs for special termination benefits related to a voluntary enhanced retirement program of $123 million for pension benefits and $19 million for other postretirement benefits.

We adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)," (SFAS No. 158) as of December 31, 2006. SFAS No. 158 amended prior accounting requirements for pension and OPEB plans. Prior to the implementation of SFAS No. 158, other comprehensive income (OCI) reflected minimum pension adjustments related to our pension plans. Our pre-tax minimum pension adjustments recognized as a component of OCI for the years ended December 31, 2006 and 2005 were net actuarial gains (losses) of $78 million and $(41) million, respectively. No amounts related to our OPEB plans were recognized as a component of OCI for the years ended December 31, 2006 and 2005.The table to the right provides a summary of amounts recognized in other comprehensive income for 2007 and other comprehensive income reclassification adjustments for amounts included in net income for 2007. The table also includes comparable items that affected regulatory assets of PEC and PEF.

(in millions)	Pension Benefits	Other Postretirement Benefits
Other comprehensive income (loss)		
Recognized for the year		
Net actuarial gain	$24	$16
Other, net	(1)	-
Reclassification adjustments		
Net actuarial loss	2	-
Other, net	1	-
Regulatory asset (increase) decrease		
Recognized for the year		
Net actuarial gain	66	82
Other, net	(8)	-
Amortized to income		
Net actuarial loss	13	2
Other, net	1	4

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

The expected long-term rates of return on plan assets were determined by considering long-term historical returns for the plans and long-term projected returns based on the plans' target asset allocation. For all pension plan assets and a substantial portion of OPEB plans assets, those benchmarks support an expected long-term rate of return between 9.0% and 9.5%. We used an expected long-term rate of 9.0%, the low end of the range, for 2007, 2006 and 2005.

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	2007	2006	2005
Discount rate	5.95%	5.65%	5.70%	5.95%	5.65%	5.70%
Rate of increase in future compensation						
Bargaining	4.25%	3.50%	3.50%	-	-	-
Supplementary plans	5.25%	5.25%	5.25%	-	-	-
Expected long-term rate of return on plan assets	9.00%	9.00%	9.00%	7.70%	8.30%	8.25%

BENEFIT OBLIGATIONS AND ACCRUED COSTS

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

Reconciliations of the changes in the benefit obligations and the funded status as of December 31, 2007 and 2006 are presented in the tables below, with each table followed by related supplementary information.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Projected benefit obligation at January 1	**$2,123**	$2,164	**$628**	$650
Service cost	**46**	45	**7**	9
Interest cost	**123**	117	**32**	33
Benefit payments	**(131)**	(174)	**(30)**	(29)
Plan amendment	**8**	18	**–**	(4)
Actuarial gain	**(27)**	(47)	**(96)**	(31)
Obligation at December 31	**2,142**	2,123	**541**	628
Fair value of plan assets at December 31	**1,996**	1,836	**75**	74
Funded status	**$(146)**	$(287)	**$(466)**	$(554)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $463 million and $2.123 billion at December 31, 2007 and 2006, respectively. Those plans had accumulated benefit obligations totaling $422 million and $2.083 billion at December 31, 2007 and 2006, respectively, and plan assets of $269 million and $1.836 billion at December 31, 2007 and 2006, respectively. The total accumulated benefit obligation for pension plans was $2.100 billion and $2.083 billion at December 31, 2007 and 2006, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Noncurrent assets	**$48**	$–	**$–**	$–
Current liabilities	**(10)**	(14)	**–**	(1)
Noncurrent liabilities	**(184)**	(273)	**(466)**	(553)
Funded status	**$(146)**	$(287)	**$(466)**	$(554)

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	**$22**	$49	**$(9)**	$7
Other, net	**6**	5	**1**	1
Recognized in regulatory assets, net				
Net actuarial loss	**136**	215	**25**	108
Other, net	**28**	22	**23**	28
Total not yet recognized as a component of net periodic cost[a]	**$192**	$291	**$40**	$144

[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 2008.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss[a]	$7	$1
Amortization of other, net[a]	2	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		Other Postretirement Benefits	
	2007	2006	**2007**	2006
Discount rate	**6.20%**	5.95%	**6.20%**	5.95%
Rate of increase in future compensation				
Bargaining	**4.25%**	4.25%	**–**	–
Supplementary plans	**5.25%**	5.25%	**–**	–
Initial medical cost trend rate for pre-Medicare Act benefits	**–**	–	**9.00%**	9.00%
Initial medical cost trend rate for post-Medicare Act benefits	**–**	–	**9.00%**	9.00%
Ultimate medical cost trend rate	**–**	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	**–**	–	**2015**	2014

The rates of increase in future compensation include the effects of cost of living adjustments and promotions.

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4, "Determining the Classification and Benefit Attribution Method for a 'Cash

Balance' Pension Plan." Therefore, effective December 31, 2003, we began to use the traditional unit credit method for purposes of measuring the benefit obligation of this plan. Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. The effects of a 1 percent change in the medical cost trend rate are shown below.

(in millions)	
1 percent increase in medical cost trend rate	
Effect on total of service and interest cost	$2
Effect on postretirement benefit obligation	31
1 percent decrease in medical cost trend rate	
Effect on total of service and interest cost	(2)
Effect on postretirement benefit obligation	(26)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our employer contributions for 2007 include contributions directly to pension plan assets of $63 million. 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 20 percent of gross benefit payments for Progress Energy. The OPEB benefits payments are also reduced by prescription drug-related federal subsidies received, which totaled $3 million and $2 million for 2007 and 2006, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Fair value of plan assets at January 1	**$1,836**	$1,770	**$74**	$76
Actual return on plan assets	**219**	222	**7**	8
Benefit payments	**(131)**	(174)	**(30)**	(29)
Employer contributions	**72**	18	**24**	19
Fair value of plan assets at December 31	**$1,996**	$1,836	**$75**	$74

	Pension Benefits		
	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2008	**2007**	2006
Equity – domestic	40%	**42%**	44%
Equity – international	15%	**25%**	23%
Debt – domestic	20%	**11%**	12%
Debt – international	10%	**12%**	9%
Other	15%	**10%**	12%
Total	100%	**100%**	100%

	Other Postretirement Benefits		
	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2008	**2007**	2006
Equity – domestic	25%	**28%**	30%
Equity – international	10%	**16%**	15%
Debt – domestic	50%	**41%**	40%
Debt – international	5%	**8%**	7%
Other	10%	**7%**	8%
Total	100%	**100%**	100%

The asset allocation for the benefit plans at the end of 2007 and 2006 and the target allocation for the plans, by asset category, are presented in the tables above.

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

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2008, we expect to make $34 million of contributions directly to pension plan assets and $1 million of discretionary contributions directly to the OPEB plan assets. The expected benefit payments for the pension benefit plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $149, $153, $155, $157, $164 and $877, respectively. The expected benefit payments for the OPEB plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $37, $40, $43, $45, $47 and $247, 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 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $3, $3, $4, $4, $5 and $39, respectively.

B. Florida Progress Acquisition

During 2000, we completed our acquisition of Florida Progress. Florida Progress' pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of Florida Progress' nonbargaining unit benefit plans were merged with our benefit plans effective January 1, 2002.

PEF continues to recover qualified plan pension costs and OPEB costs in rates as if the acquisition had not occurred. The information presented in Note 16A is adjusted as appropriate to reflect PEF's rate treatment.

17. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

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

As discussed in Note 15, in connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income (See Note 20). At December 31, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively.

A. Commodity Derivatives

GENERAL

Most of our physical commodity contracts are not derivatives pursuant to SFAS No. 133 or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

In 2003, we recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the provisions of FASB Derivatives Implementation Group Issue C20, "Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature" (DIG Issue C20). The related liability is being amortized to earnings over the term of the related contract (See Note 20). At December 31, 2007 and 2006, the remaining liability was $10 million and $14 million, respectively.

DISCONTINUED OPERATIONS

As discussed in Note 3A, our subsidiary, PVI, entered into a series of transactions to sell or assign substantially all of its CCO physical and commercial assets and liabilities. On June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of the Georgia Contracts, forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represented substantially all of our nonregulated energy marketing and trading operations. The sale of the generation assets closed on June 11, 2007. Additionally, we sold Gas on October 2, 2006 (See Note 3C). At December 31, 2007, with the exception of the oil price hedge instruments discussed below, our discontinued operations did not have outstanding positions in derivative instruments. For the year ended December 31, 2007, $88 million of after-tax gains from derivative instruments related to our nonregulated energy marketing and trading operations were included in discontinued operations on the Consolidated Statements of Income.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Notes 1C and 3J, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate Ceredo in accordance with FIN 46R, but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. At December 31, 2007, the fair value of all of these contracts was recorded as a $234 million short-term derivative asset position, including $79 million at Ceredo. The fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet (See Note 6A). As discussed in Note 3B, on October 12, 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts. Of this amount, $57 million was attributable to Ceredo of which $42 million was attributed to minority interest for the portion of the gain subsequent to the disposal of Ceredo.

At December 31, 2006, derivative assets of $107 million and derivative liabilities of $31 million were included in assets to be divested and liabilities to be divested, respectively, on the Consolidated Balance Sheet. Due to the divestitures discussed above, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts would be fulfilled, and cash flow hedge accounting for the contracts was discontinued beginning in the second quarter of 2006 for Gas and in the fourth quarter of 2006 for CCO. Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. For the years ended December 31, 2006 and 2005, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ended December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ended December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges.

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. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets on the Consolidated Balance Sheets, respectively, until the contracts are settled (See Note 7A). Once settled, any realized gains or losses are passed through the fuel clause. During the year ended December 31, 2007, PEC recorded a net realized loss of $9 million. PEC's net realized gains and losses were not material during the years ended December 31, 2006 and 2005. During the years ended December 31, 2007, 2006 and 2005, PEF recorded a net realized loss of $46 million, a net realized gain of $39 million and a net realized gain of $70 million, respectively.

Excluding amounts receiving regulatory accounting treatment and amounts related to our discontinued operations discussed above, gains and losses from contracts entered into for economic hedging purposes were not material to our results of operations during the years ended December 31, 2007, 2006 and 2005. Excluding derivative assets and derivative liabilities to be divested discussed above, we did not have material outstanding positions in such contracts at December 31, 2007 and 2006, other than those receiving regulatory accounting treatment at PEC and PEF, as discussed below.

At December 31, 2007, the fair value of PEC's commodity derivative instruments was recorded as a $19 million long-term derivative asset position included in other assets and deferred debits and a $3 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, PEC did not have material outstanding positions in such contracts.

At December 31, 2007, the fair value of PEF's commodity derivative instruments was recorded as a $60 million short-term derivative asset position included in prepayments and other current assets, a $90 million long-term derivative asset position included in derivative assets, and a $15 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, the fair value of such instruments was recorded as a $2 million long-term derivative asset position included in derivative assets, an $87 million short-term derivative liability position included in other current liabilities, and a $36 million long-term derivative liability position included in other liabilities and deferred credits on the Consolidated Balance Sheet.

CASH FLOW HEDGES

Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. At December 31, 2007 and 2006, we did not have material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our results of operations for 2007, 2006 and 2005.

At December 31, 2007 and 2006, the amount recorded in our accumulated other comprehensive income related to commodity cash flow hedges was not material.

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

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

CASH FLOW HEDGES

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

(in millions)	**2007**	2006
Fair value of liabilities	**$(12)**	$(2)

Gains and losses from cash flow hedges are recorded in accumulated other comprehensive income and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The ineffective portion of interest rate cash flow hedges was not material to our results of operations for 2007, 2006 and 2005.

The following table presents selected information related to interest rate cash flow hedges included in accumulated other comprehensive income at December 31, 2007:

(term in years/millions of dollars)	
Maximum term	Less than 1
Accumulated other comprehensive loss, net of tax[a]	$(24)
Portion expected to be reclassified to earnings during the next 12 months[b]	$(2)

[a] Includes amounts related to terminated hedges.

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

At December 31, 2006, including amounts related to terminated hedges, we had $14 million of after-tax deferred losses, including $5 million of after-tax deferred losses at PEC and $1 million of after-tax deferred losses at PEF, recorded in accumulated other comprehensive income related to interest rate cash flow hedges.

At December 31, 2007 and 2006, PEC had $200 million notional and $50 million notional, respectively, of interest rate cash flow hedges. During 2007, PEC entered into a combined $150 million notional of forward starting swaps and amended its $50 million notional 10-year forward starting swap in order to move the maturity date from October 1, 2017 to April 1, 2018, which now requires mandatory cash settlement on April 1, 2008.

In 2007, PEF entered into a combined $225 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. At December 31, 2006, PEF had $50 million notional of interest rate cash flow hedges. All of PEF's forward starting swaps were terminated on September 13, 2007, in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. On January 8, 2008, PEF entered into a combined $200 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At December 31, 2007, we had no open interest rate fair value hedges. At December 31, 2006, we had $50 million notional of interest rate fair value hedges.

18. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2007, the Parent had issued $433 million of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheet.

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of PUHCA 1935. The repeal of PUHCA 1935 effective February 8, 2006, and subsequent regulation by the FERC did not change our current intercompany services. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, construction management and other centralized administrative, management and support services. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. Billings from affiliates are capitalized or expensed depending on the nature of the services rendered.

PESC provides the majority of the affiliated services under the approved agreements. Services provided by PESC during 2007, 2006 and 2005 to PEC amounted to $182 million, $188 million and $202 million, respectively, and services provided to PEF were $174 million, $165 million and $169 million, respectively.

Progress Fuels sold coal to PEF at cost in 2007 and 2006 and for an insignificant profit in 2005. These intercompany revenues and expenses are eliminated in consolidation; however, in accordance with SFAS No. 71, profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. Sales, net of insignificant profits, if any, of $2 million, $321 million and $402 million for the years ended December 31, 2007, 2006 and 2005, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income. In 2006, PEF began entering into coal contracts on its own behalf.

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

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

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

Our former Coal and Synthetic Fuels segment was previously involved in the production and sale of coal-based solid synthetic fuels as defined under the Code, the operation of synthetic fuels facilities for third parties and coal terminal services. In 2007, we reclassified the operations of our synthetic fuels businesses and coal terminal services as discontinued operations (See Note 3B). For comparative purposes, prior year results have been restated to conform to the current segment presentation.

The postretirement and severance charges incurred in 2005 resulted from a workforce restructuring and voluntary enhanced retirement program that was approved in February 2005 and concluded in December 2005. Postretirement and severance charges reclassified to discontinued operations are not included in the table below.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between PEF and the former Coal and Synthetic Fuels segment, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and the former Coal and

Synthetic Fuels segment are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. The profits realized for 2007, 2006 and 2005 were not significant. Prior to 2006, income tax expense (benefit) by segment includes the Parent's allocation to profitable subsidiaries of income tax benefits not related to acquisition interest expense in accordance with the Tax Agreement. Due to the repeal of PUHCA 1935, the Parent stopped allocating these tax benefits in 2006.

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

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2007					
Revenues					
Unaffiliated	$4,385	$4,748	$20	$–	$9,153
Intersegment	–	1	393	(394)	–
Total revenues	4,385	4,749	413	(394)	9,153
Depreciation and amortization	519	366	20	–	905
Interest income	21	9	55	(51)	34
Total interest charges, net	210	173	258	(53)	588
Income tax expense (benefit)	295	144	(105)	–	334
Segment profit (loss)	498	315	(120)	–	693
Total assets	11,962	10,004	16,383	(12,115)	26,234
Capital and investment expenditures	941	1,262	3	(2)	2,204
As of and for the year ended December 31, 2006					
Revenues					
Unaffiliated	$4,086	$4,638	$–	$–	$8,724
Intersegment	–	1	729	(730)	–
Total revenues	4,086	4,639	729	(730)	8,724
Depreciation and amortization	571	404	36	–	1,011
Interest income	25	15	85	(66)	59
Total interest charges, net	215	150	326	(67)	624
Income tax expense (benefit)	265	193	(119)	–	339
Segment profit (loss)	454	326	(229)	–	551
Total assets	12,020	8,593	15,421	(11,293)	24,741
Capital and investment expenditures	808	741	12	(9)	1,552
As of and for the year ended December 31, 2005					
Revenues					
Unaffiliated	$3,991	$3,955	$2	$–	$7,948
Intersegment	–	–	839	(839)	–
Total revenues	3,991	3,955	841	(839)	7,948
Depreciation and amortization	561	334	31	–	926
Interest income	8	1	94	(90)	13
Total interest charges, net	192	126	342	(85)	575
Postretirement and severance charges	55	102	1	–	158
Income tax expense (benefit)	239	121	(62)	–	298
Segment profit (loss)	490	258	(225)	–	523
Total assets	11,502	8,318	18,278	(13,673)	24,425
Capital and investment expenditures	682	543	19	(19)	1,225

20. OTHER INCOME AND OTHER EXPENSE

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

(in millions)	2007	2006	2005
Other income			
Nonregulated energy and delivery services income	**$36**	$41	$32
DIG Issue C20 amortization (Note 17A)	**4**	5	7
Contingent value obligation unrealized gain (Note 15)	**2**	–	6
Gain on sale of Level 3 stock[(a)]	**–**	32	–
Investment gains	**9**	4	4
Income from equity investments	**2**	1	1
AFUDC equity	**51**	21	16
Reversal of indemnification liability (Note 21B)	**–**	29	–
Other	**15**	13	16
Total other income	**119**	146	82
Other expense			
Nonregulated energy and delivery services expenses	**24**	27	23
Donations	**22**	20	18
Contingent value obligation unrealized loss (Note 15)	**4**	25	–
Investment losses	**4**	–	1
Loss from equity investments	**5**	3	7
Loss on debt redemption[(b)]	**–**	59	–
FERC audit settlement	**–**	–	7
Indemnification liability (Note 21B)	**–**	13	16
Other	**16**	15	11
Total other expense	**75**	162	83
Other, net	**$44**	$(16)	$(1)

(a) Other income includes pre-tax gains of $32 million for the year ended December 31, 2006, from the sale of approximately 20 million shares of Level 3 stock received as part of the sale of our interest in PT LLC (See Note 3E). These gains are prior to the consideration of minority interest.

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

21. ENVIRONMENTAL MATTERS

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

A. Hazardous and Solid Waste

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the United States Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida, or potentially responsible party (PRP) groups as described below in greater detail. Various materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. A discussion of sites by legal entity follows.

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

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

(in millions)	2007	2006
PEC		
MGP and other sites[a]	$16	$22
PEF		
Remediation of distribution and substation transformers	31	43
MGP and other sites	17	18
Total PEF environmental remediation accruals[b]	48	61
Progress Energy nonregulated operations	–	3
Total Progress Energy environmental remediation accruals	$64	$86

[a] Expected to be paid out over one to five years.
[b] Expected to be paid out over one to fifteen years.

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

In 2001, we, through our Progress Fuels subsidiary, established an accrual to address indemnities and retained an environmental liability associated with the sale of our Inland Marine Transportation business. At December 31, 2006, the remaining accrual balance was approximately $3 million. For the year ended December 31, 2007, the accrual was reduced by approximately $3 million due to a reduction in the anticipated scope of work based on responses from regulatory agencies. Expenditures related to this liability were not material during 2007 and 2006.

On March 24, 2005, we completed the sale of our Progress Rail subsidiary. In connection with the sale, we incurred indemnity obligations related to certain pre-closing liabilities, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC

There are currently eight former MGP sites and a number of other sites associated with PEC that have required or are anticipated to require investigation and/or remediation. Three of these sites are in the long-term monitoring phase.

For the year ended December 31, 2007, including the Carolina Transformer site, the Ward Transformer site and MGP sites discussed below, PEC's accrual was reduced by a net amount of approximately $2 million and PEC spent approximately $4 million. For the year ended December 31, 2006, PEC accrued approximately $21 million and spent approximately $6 million. In October 2006, PEC received orders from the NCUC and SCPSC to defer and amortize certain environmental remediation expenses, net of insurance proceeds (See Note 7B).

For the year ended December 31, 2006, based upon newly available data for several of PEC's MGP sites, which had individual site remediation costs ranging from approximately $2 million to $4 million, a remediation liability of approximately $12 million was recorded for the minimum estimated total remediation cost for all of PEC's remaining MGP sites. The maximum amount of the range for all the sites cannot be determined at this time as one of the remaining sites is significantly larger than the sites for which we have historical experience. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

During the fourth quarter of 2004, the EPA advised PEC that it had been identified as a PRP at the Ward Transformer site located in Raleigh, N.C. The EPA offered PEC and a number of other PRPs the opportunity to negotiate cleanup of the site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the site. For the year ended December 31, 2006, based upon continuing assessment work performed at the site, PEC recorded an additional $9 million accrual for its portion of the estimated remediation costs. At December 31, 2006, after cumulative expenditures for the Ward site of approximately $3 million, PEC's recorded liability for the site was approximately $9 million. During 2007, the PRP agreement was amended to include an additional participating PRP, which reduced PEC's allocable share, and the estimated scope of work increased. These factors resulted in a net reduction to PEC's accrual for this site. At December 31, 2007, PEC's recorded liability for the site was approximately $6 million. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. The outcome of this matter cannot be predicted.

The EPA has also proposed, but not yet selected, a final remedial action plan to address stream segments downstream from the Ward Transformer site. The outcome of this matter cannot be predicted.

In September 2005, the EPA advised PEC that it had been identified as a PRP at the Carolina Transformer site located in Fayetteville, N.C. The EPA offered PEC and a number of other PRPs the opportunity to share in the reimbursement to the EPA of past expenditures in addressing conditions at the site, which are currently approximately $33 million. During the year ended December 31, 2007, a settlement was reached between the PRPs and the EPA, and PEC recorded and paid an immaterial amount for its share of the settlement.

PEF

PEF has received approval from the FPSC for recovery of the majority of costs associated with the remediation of distribution and substation transformers through the Environmental Cost Recovery Clause (ECRC). Under agreements with the Florida Department of Environmental Protection, PEF is in the process of examining distribution transformer sites and substation sites for mineral oil-impacted soil remediation caused by equipment integrity issues. PEF has reviewed a number of distribution transformer sites and all substation sites. Based on changes to the estimated time frame for inspections of distribution transformer sites, PEF currently expects to have completed this review by the end of 2008. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC. For the year ended December 31, 2007, PEF accrued approximately $10 million due to an increase in estimated remediation costs and spent approximately $22 million related to the remediation of transformers. For the year ended December 31, 2006, PEF accrued approximately $42 million due to additional sites expected to require remediation and spent approximately $19 million related to the remediation of transformers. At December 31, 2007, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

The amounts for MGP and other sites, in the table above, relate to two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation. The amounts include approximately $12 million in insurance claim settlement proceeds received in 2004, which are restricted for use in addressing costs associated with environmental liabilities. For the year ended December 31, 2007, PEF made no accruals and spent approximately $1 million. For the year ended December 31, 2006, PEF made no accruals and PEF's expenditures were not material to our results of operations or financial condition.

B. Air and Water Quality

We are 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 include the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call), the Clean Smokestacks Act and mercury regulation (see "Other Matters – Environmental Matters" for discussion regarding Clean Air Mercury Rule (CAMR)). At December 31, 2007, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.567 billion, including $1.244 billion at PEC and $323 million at PEF. At December 31, 2006, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $932 million, including $904 million at PEC and $28 million at PEF.

As discussed in Note 7A, in June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. Two of PEC's largest coal-fired generating units (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. Pursuant to joint ownership agreements, the joint owners are required to pay a portion of the costs of owning and operating these plants. PEC has determined that the most cost-effective Clean Smokestacks Act compliance strategy is to maximize the SO_2 removal from its larger coal-fired units, including Roxboro No. 4 and Mayo, so as to avoid the installation of expensive emission controls on its smaller coal-fired units. In order to address the joint owner's concerns that such a compliance strategy would result in a disproportionate share of the cost of compliance for the jointly owned units, PEC entered into an agreement with the joint owner to limit its aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately $38 million. PEC recorded a related liability for the joint owner's share of estimated costs in excess of the contract amount. At December 31, 2007, and 2006, the amount of the liability was $30 million and $29 million, respectively, based upon the respective current estimates for Clean Smokestacks Act compliance. Because PEC has taken a system-wide compliance approach, its North Carolina retail ratepayers have significantly benefited from the strategy of focusing emission reduction efforts on the jointly owned units, and, therefore, PEC believes that any costs in excess of the joint owner's share should be recovered from North Carolina retail ratepayers, consistent with other capital expenditures associated with PEC's compliance with the Clean Smokestacks Act. In 2006, PEC notified the NCUC of its intent to record these estimated excess costs as part of the $569 million amortization required to be recorded by December 31, 2007, and accordingly, recorded the indemnification expense to Clean Smokestacks Act amortization. In a settlement agreement provisionally approved by the NCUC on December 20, 2007, eligible compliance costs in excess of the joint owner's share will be treated in the same manner as PEC's Clean Smokestacks Act compliance costs in excess of the original estimated compliance costs, as ultimately approved by the NCUC (See Note 7A).

22. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2007, the table below reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due.

(in millions)	2008	2009	2010	2011	2012	Thereafter
Fuel	$2,018	$1,745	$1,202	$1,001	$675	$5,103
Purchased power	455	422	409	443	415	3,756
Construction obligations	714	211	42	–	–	–
Other purchase obligations	94	39	32	16	16	64
Total	$3,281	$2,417	$1,685	$1,460	$1,106	$8,923

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel. Our payments under these commitments were $2.360 billion, $1.628 billion and $1.470 billion for 2007, 2006 and 2005, respectively.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (primarily QFs) with expiration dates ranging from 2008 to 2030. These purchased power contracts generally provide for capacity and energy payments.

PEC has a long-term agreement for the purchase of power and related transmission services from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The agreement provides for the purchase of 250 MW of capacity through 2009 with estimated minimum annual payments of approximately $42 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $77 million, $80 million and $71 million for 2007, 2006 and 2005, respectively.

PEC executed two long-term agreements for the purchase of power from Broad River LLC's Broad River facility (Broad River). One agreement provides for the purchase of approximately 500 MW of capacity through 2021 with an original minimum annual payment of approximately $16 million, primarily representing capital-related capacity costs. The second agreement provided for the additional purchase of approximately 335 MW of capacity through 2022 with an original minimum annual payment of approximately $16 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River agreements amounted to $39 million, $40 million and $44 million in 2007, 2006 and 2005, respectively.

In 2007, PEC executed a long-term agreement for the purchase of power from Southern Power Company. The agreement provides for capacity purchases of 305 MW for 2010, 310 MW for 2011 and 150 MW annually thereafter through 2019. Estimated payments for capacity and energy under the agreement are $22 million for 2010, $33 million for 2011 and $14 million annually thereafter through 2019. PEC has various pay-for-performance contracts with QFs for approximately 195 MW of capacity expiring at various times through 2014. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $95 million, $182 million and $112 million in 2007, 2006 and 2005, respectively.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $161 million, $162 million and $175 million for 2007, 2006 and 2005, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $70 million annually through 2011, $50 million for 2012 and $32 million annually thereafter through 2016.

PEF has ongoing purchased power contracts with certain QFs for 965 MW of capacity with expiration dates ranging from 2008 to 2030. 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 generating capacity of each of the facilities. All commitments, except one for 75 MW, have been approved by the FPSC. Total capacity purchases under these contracts amounted to $288 million, $277 million and $262 million for 2007, 2006 and 2005, respectively. At December 31, 2007, minimum expected future capacity payments under these contracts were $297 million, $263 million, $267 million, $281 million and $292 million for 2008 through 2012, respectively, and $3.053 billion thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

In January 2006, PEF entered into a conditional contract with Gulfstream Natural Gas System, L.L.C. (Gulfstream) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from September 1, 2008, through January 1, 2031. The total cost to PEF associated with this agreement is approximately $777 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of the necessary related expansions to Gulfstream's natural gas pipeline system, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In July 2006, PEF entered into a conditional contract with Devon Gas Services for the supply of natural gas to augment PEF's gas supply needs for the period from May to September for the years 2008 through 2011. The total cost to PEF associated with this agreement is approximately $251 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate pipeline expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Cross Timbers Energy Services, Inc. for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2013. The total cost to PEF associated with this agreement is approximately $1.026 billion. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Southeast Supply Header, L.L.C. (SESH) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2023. The total cost to PEF associated with this agreement is approximately $271 million. The transaction is subject to several conditions precedent, including FPSC approval, the completion and commencement of operation of the SESH pipeline project, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with a private oil and gas company for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through March 31, 2013. The total cost to PEF associated with this agreement is approximately $146 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In January and February 2007, PEF entered into conditional contracts with Chevron Natural Gas for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, to May 31, 2013. The total cost to PEF associated with these agreements is approximately $935 million. The transactions are subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate pipeline expansions, and other standard closing conditions. Due to the conditions of these agreements the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $675 million, $365 million and $91 million for 2007, 2006 and 2005, respectively. Our future obligations related to Clean Smokestacks Act capital projects are $84 million for 2008 and $22 million for 2009. We have purchase obligations related to various capital projects related to new generation and Florida CAIR. Our future obligations under these contracts are $631 million, $188 million and $42 million for 2008 through 2010, respectively.

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and a PEF service agreement related to the Hines Energy Complex. Our payments under these agreements were $97 million, $122 million and $100 million for 2007, 2006 and 2005, respectively.

We have entered into various other contractual obligations primarily related to capacity and service contracts for operational services associated with discontinued CCO operations. Total payments under these contracts were $8 million, $18 million and $17 million for 2007, 2006 and 2005, respectively. Estimated future payments under these contracts of $6 million are not reflected in the contractual cash obligations table above. Included in these contracts are purchase obligations with a counterparty for pipeline capacity through 2009.

PEC has various purchase obligations for emission obligations, limestone supply and the purchase of capital parts. Total purchases under these contracts were $21 million, $2 million and $10 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $22 million for 2008, $4 million each for 2009 and 2010, and $3 million each for 2011 and 2012 and $13 million thereafter.

PEC has various purchase obligations related to reactor vessel head replacements, power uprates and spent fuel storage. Total purchases under these contracts were $8 million for 2006 and $13 million for 2005, with no purchases in 2007. Future obligations under these contracts are for spent fuel storage and total $5 million, $8 million, $3 million and $1 million for 2008 through 2011, respectively.

PEF has long-term service agreements for the Hines Energy Complex. Total payments under these contracts were $11 million, $12 million and $8 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $21 million, $14 million, $19 million, $12 million and $12 million for 2008 through 2012, respectively, with approximately $50 million payable thereafter.

PEF has various purchase obligations and contractual commitments related to the purchase and replacement of machinery. Total payments under these contracts were $22 million, $21 million and $34 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $8 million and $6 million for 2008 and 2009, respectively.

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 $40 million, $42 million and $38 million for 2007, 2006 and 2005, respectively. Our purchased power expense under agreements classified as operating leases was approximately $69 million, $60 million and $14 million in 2007, 2006 and 2005, respectively.

Assets recorded under capital leases at December 31 consisted of:

(in millions)	**2007**	2006
Buildings	**$267**	$84
Less: Accumulated amortization	**(20)**	(12)
Total	**$247**	$72

At December 31, 2007, 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
2008	$28	$62
2009	29	41
2010	28	25
2011	28	20
2012	28	38
Thereafter	308	554
Minimum annual payments	449	$740
Less amount representing imputed interest	(202)	
Present value of net minimum lease payments under capital leases	$247	

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 2007, PEF entered into a purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $28 million from 2012 through 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 annual payments of approximately $5 million from 2007 through 2026 for a total of approximately $103 million. The lease term provides for no payments during the last 20 years of the lease, during which period approximately $51 million of rental expense will be recorded in the Consolidated Statements of Income.

In 2006, PEF extended the terms of an agreement for purchased power, which is classified as a capital lease, for an additional 10 years. The agreement calls for minimum annual payments of approximately $21 million from 2007 through 2024 for a total of approximately $348 million. Due to the conditions of the agreement, the capital lease was not recorded on our Consolidated Balance Sheets until 2007.

In 2006, PEF entered into an agreement for purchased power, which is classified as a capital lease. Due to the conditions of the agreement, the capital lease will not be recorded on the Consolidated Balance Sheets until approximately 2011. Therefore, this capital lease is not included in the table above. The agreement calls for minimum annual payments of approximately $8 million from 2012 through 2036 for a total of approximately $208 million.

Excluding the Utilities, we are also a lessor of land, buildings and other types of properties we own under operating leases with various terms and expiration dates. The leased buildings are depreciated under the same terms as other buildings included in diversified business property. Minimum rentals receivable under noncancelable leases are approximately $8 million, $7 million, $5 million, $4 million and $2 million for 2008 through 2012, respectively. Rents received under these operating leases totaled $8 million, $9 million and $8 million for 2007, 2006 and 2005, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $10 million for 2008 and none thereafter. PEC's rents received are contingent upon usage and totaled $33 million for 2007 and $31 million each for 2006 and 2005. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $78 million, $72 million and $63 million for 2007, 2006 and 2005, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2008 and thereafter.

C. Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties, which are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2007, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Balance Sheets.

At December 31, 2007, 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, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations, which are within the scope of FIN 45. Related to the sales of businesses, the latest notice period extends until 2012 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. In 2005, PEC entered into an agreement with the joint owner of certain facilities at the Mayo and Roxboro plants to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification (See Note 21B). PEC's maximum exposure cannot be determined. At December 31, 2007, the estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $427 million. At December 31, 2007 and 2006, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $80 million and $60 million, respectively. As current estimates change, it is possible that additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

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

D. Other Commitments and Contingencies

SPENT NUCLEAR FUEL MATTERS

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

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

The DOE and the Utilities agreed to, and the trial court entered, a stay of proceedings, in order to allow for possible efficiencies due to the resolution of legal and factual issues in previously filed cases in which similar claims are being pursued by other plaintiffs. These issues may include, among others, so-called "rate issues," or the minimum mandatory schedule for the acceptance of spent nuclear fuel and high-level radioactive waste by which the government was contractually obligated to accept contract holders' spent nuclear fuel and/or high-level waste, and issues regarding recovery of damages under a partial breach of contract theory that will be alleged to occur in the future. These issues have been presented in the trials or appeals during 2006 and 2007. Resolution of these issues in other cases could facilitate agreements by the parties in the Utilities' lawsuit, or at a minimum, inform the court of decisions reached by other courts if they remain contested and require resolution in this case. In July 2005, the parties jointly requested a continuance of the stay through December 15, 2005, which the trial court granted. Subsequently, the trial court continued the stay until March 17, 2006. The trial court lifted the stay on March 22, 2006, and discovery commenced. The trial court issued a scheduling order on March 23, 2006, and the case went to trial beginning November 5, 2007. Closing arguments are anticipated in the second quarter of 2008 with a ruling expected later in 2008. The Utilities cannot predict the outcome of this matter. In the event that the Utilities recover damages in this matter, such recovery is not expected to have a material impact on the Utilities' results of operations given the anticipated regulatory and accounting treatment.

In July 2002, Congress passed an override resolution to Nevada's veto of the DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nev. In January 2003, the state of Nevada; Clark County, Nev.; and the city of Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged the EPA's radiation standards for Yucca Mountain. On July 9, 2004, the Court rejected the challenge to the constitutionality of the resolution approving Yucca Mountain, but ruled that the EPA was wrong to set a 10,000-year compliance period in the radiation protection standard. In August 2005, the EPA issued new proposed standards. The proposed standards include a 1,000,000-year compliance period in the radiation protection standard. Comments were due November 21, 2005, and are being reviewed by the EPA. The DOE originally planned to submit a license application to the NRC to construct the Yucca Mountain facility by the end of 2004. However, in November 2004, the DOE announced it would not submit the license application until mid-2005 or later. The DOE did not submit the license application in 2005 and subsequently reported that the license application would be submitted by June 2008 if full funding was obtained for the project. The DOE requested $545 million for fiscal year 2007 and received $445 million. The DOE requested $495 million for fiscal year 2008. However, Congress passed an appropriations bill which allocates $390 million in fiscal year 2008 for DOE's Yucca Mountain repository program. As a result of the fiscal year budget reductions, the schedule for submitting the license application is being re-evaluated by the DOE. The impact to the Yucca Mountain repository program cannot be predicted at this time.

On October 19, 2007, the DOE certified the regulatory compliance of the document database that will be used by all parties involved in the federal licensing process for the Yucca Mountain facility. The NRC did not uphold the DOE's prior certification in 2004 in response to challenges from the state of Nevada. The state again is expected to challenge the DOE's certification process. The DOE has stated that if legislative changes requested by the Bush administration are enacted, the repository may be able to accept spent nuclear fuel starting in 2017, but 2020 is more probable due to anticipated litigation by the state of Nevada. The Utilities cannot predict the outcome of this matter.

With certain modifications and additional approvals by the NRC, including the installation 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 extensions, for their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pools through the expiration of its operating license, including any license extensions.

SYNTHETIC FUELS MATTERS

A number of our subsidiaries and affiliates are parties to two lawsuits arising out of an Asset Purchase Agreement dated as of October 19, 1999, by and among U.S. Global, LLC (Global); the Earthco synthetic fuels facilities (Earthco); certain affiliates of Earthco; EFC Synfuel LLC (which is owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to Purchase Agreement as of August 23, 2000 (the Asset Purchase Agreement). Global has asserted (1) that pursuant to the Asset Purchase Agreement, it is entitled to an interest in two synthetic fuels facilities currently owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it is entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities and (3) a number of tort claims related to the contracts.

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

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

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

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

In January 2008, Global agreed to simplify the Florida action by dismissing the tort claims. The suit continues now under contract theories alone. We cannot predict the outcome of this matter.

OTHER LITIGATION MATTERS

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

23. CONDENSED CONSOLIDATING STATEMENTS

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

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing $300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities) and using the proceeds thereof to purchase from Funding Corp. $300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039 (Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes

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

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

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. As of December 31, 2007, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a special-purpose entity and in accordance with the provisions of FIN 46R, we deconsolidated the Trust on December 31, 2003. The deconsolidation was not material to our financial statements. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In the following tables, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the financial results of Florida Progress. The Other column includes the consolidated financial results of all other nonguarantor subsidiaries and elimination entries for all intercompany transactions. All applicable corporate expenses have been allocated appropriately among the guarantor and nonguarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other nonguarantor subsidiaries operated as independent entities. The accompanying condensed consolidating financial statements have been restated for all periods presented to reflect the operations of Terminals and the synthetic fuels businesses as discontinued operations as described in Note 3B.

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$–	$4,768	$4,385	$9,153
Affiliate revenues	–	89	(89)	–
Total operating revenues	–	4,857	4,296	9,153
Operating expenses				
Fuel used in electric generation	–	1,764	1,381	3,145
Purchased power	–	882	302	1,184
Operation and maintenance	10	834	998	1,842
Depreciation and amortization	–	369	536	905
Taxes other than on income	–	309	192	501
Other	–	20	10	30
Total operating expenses	10	4,178	3,419	7,607
Operating (loss) income	(10)	679	877	1,546
Other income, net	27	47	4	78
Interest charges, net	203	198	187	588
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(186)	528	694	1,036
Income tax (benefit) expense	(79)	117	296	334
Equity in earnings of consolidated subsidiaries	596	–	(596)	–
Minority interest in subsidiaries' income, net of tax	–	(9)	–	(9)
Income (loss) from continuing operations	489	402	(198)	693
Discontinued operations, net of tax	15	(59)	(145)	(189)
Net income (loss)	$504	$343	$(343)	$504

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$–	$4,637	$4,087	$8,724
Affiliate revenues	–	41	(41)	–
Total operating revenues	–	4,678	4,046	8,724
Operating expenses				
Fuel used in electric generation	–	1,835	1,173	3,008
Purchased power	–	766	334	1,100
Operation and maintenance	14	684	885	1,583
Depreciation and amortization	–	406	605	1,011
Taxes other than on income	–	309	191	500
Other	–	21	14	35
Total operating expenses	14	4,021	3,202	7,237
Operating (loss) income	(14)	657	844	1,487
Other (expense) income, net	(33)	55	21	43
Interest charges, net	276	182	166	624
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	530	699	906
Income tax (benefit) expense	(123)	174	288	339
Equity in earnings of consolidated subsidiaries	779	–	(779)	–
Minority interest in subsidiaries' income, net of tax	–	(16)	–	(16)
Income (loss) from continuing operations	579	340	(368)	551
Discontinued operations, net of tax	(8)	359	(331)	20
Net income (loss)	$571	$699	$(699)	$571

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2005 *(in millions)*	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$-	$3,956	$3,992	$7,948
Affiliate revenues	–	188	(188)	–
Total operating revenues	–	4,144	3,804	7,948
Operating expenses				
Fuel used in electric generation	–	1,323	1,036	2,359
Purchased power	–	694	354	1,048
Operation and maintenance	12	852	906	1,770
Depreciation and amortization	–	337	589	926
Taxes other than on income	4	279	177	460
Other	–	(5)	2	(3)
Total operating expenses	16	3,480	3,064	6,560
Operating (loss) income	(16)	664	740	1,388
Other income (expense), net	66	(1)	(53)	12
Interest charges, net	305	163	107	575
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(255)	500	580	825
Income tax (benefit) expense	(64)	96	266	298
Equity in earnings of consolidated subsidiaries	884	–	(884)	–
Minority interest in subsidiaries' income, net of tax	–	(4)	–	(4)
Income (loss) from continuing operations	693	400	(570)	523
Discontinued operations, net of tax	4	(26)	195	173
Cumulative effect of change in accounting principle, net of tax	–	–	1	1
Net income (loss)	$697	$374	$(374)	$697

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$–	$7,600	$9,005	$16,605
Current assets				
Cash and cash equivalents	185	43	27	255
Short-term investments	–	–	1	1
Notes receivable from affiliated companies	157	149	(306)	–
Deferred fuel cost	–	6	148	154
Assets to be divested	–	48	4	52
Prepayments and other current assets	21	1,211	1,081	2,313
Total current assets	363	1,457	955	2,775
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,969	–	(10,969)	–
Goodwill	–	1	3,654	3,655
Other assets and deferred debits	149	1,551	1,551	3,251
Total deferred debits and other assets	11,118	1,552	(5,764)	6,906
Total assets	$11,481	$10,609	$4,196	$26,286
Capitalization				
Common stock equity	$8,422	$3,052	$(3,052)	$8,422
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	81	3	84
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,597	2,686	3,183	8,466
Total capitalization	11,019	6,162	155	17,336
Current liabilities				
Current portion of long-term debt	–	577	300	877
Short-term debt	201	–	–	201
Notes payable to affiliated companies	–	227	(227)	–
Regulatory liabilities	–	173	–	173
Liabilities to be divested	–	8	–	8
Other current liabilities	215	1,028	746	1,989
Total current liabilities	416	2,013	819	3,248
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	59	302	361
Regulatory liabilities	–	1,316	1,223	2,539
Accrued pension and other benefits	12	347	404	763
Capital lease obligations	–	224	15	239
Other liabilities and deferred credits	34	488	1,278	1,800
Total deferred credits and other liabilities	46	2,434	3,222	5,702
Total capitalization and liabilities	$11,481	$10,609	$4,196	$26,286

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$–	$6,337	$8,908	$15,245
Current assets				
Cash and cash equivalents	153	40	72	265
Short-term investments	21	–	50	71
Notes receivable from affiliated companies	58	37	(95)	–
Deferred fuel cost	–	–	196	196
Assets to be divested	–	121	845	966
Prepayments and other current assets	27	1,060	1,029	2,116
Total current assets	259	1,258	2,097	3,614
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,740	–	(10,740)	–
Goodwill	–	1	3,654	3,655
Other assets and deferred debits	126	1,556	1,511	3,193
Total deferred debits and other assets	10,866	1,557	(5,575)	6,848
Total assets	$11,125	$9,152	$5,430	$25,707
Capitalization				
Common stock equity	$8,286	$2,708	$(2,708)	$8,286
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	6	4	10
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,582	2,512	3,470	8,564
Total capitalization	10,868	5,569	787	17,224
Current liabilities				
Current portion of long-term debt	–	124	200	324
Notes payable to affiliated companies	–	77	(77)	–
Liabilities to be divested	–	72	176	248
Other current liabilities	210	1,224	814	2,248
Total current liabilities	210	1,497	1,113	2,820
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	61	251	312
Regulatory liabilities	–	1,091	1,452	2,543
Accrued pension and other benefits	14	377	566	957
Other liabilities and deferred credits	33	557	1,261	1,851
Total deferred credits and other liabilities	47	2,086	3,530	5,663
Total capitalization and liabilities	$11,125	$9,152	$5,430	$25,707

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$76	$489	$687	$1,252
Investing activities				
Gross property additions	–	(1,218)	(755)	(1,973)
Nuclear fuel additions	–	(44)	(184)	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	51	624	675
Purchases of available-for-sale securities and other investments	–	(640)	(773)	(1,413)
Proceeds from sales of available-for-sale securities and other investments	21	640	791	1,452
Changes in advances to affiliates	(99)	(112)	211	–
Return of investment in consolidated subsidiary	340	–	(340)	–
Other investing activities	(31)	32	29	30
Net cash provided (used) by investing activities	231	(1,291)	(397)	(1,457)
Financing activities				
Issuance of common stock	151	–	–	151
Dividends paid on common stock	(627)	–	–	(627)
Dividends paid to parent	–	(10)	10	–
Proceeds from issuance of short-term debt with original maturities greater than 90 days	176	–	–	176
Net increase in short-term debt	25	–	–	25
Proceeds from issuance of long-term debt, net	–	739	–	739
Retirement of long-term debt	–	(124)	(200)	(324)
Changes in advances from affiliates	–	151	(151)	–
Other financing activities	–	49	6	55
Net cash (used) provided by financing activities	(275)	805	(335)	195
Net increase (decrease) in cash and cash equivalents	32	3	(45)	(10)
Cash and cash equivalents at beginning of year	153	40	72	265
Cash and cash equivalents at end of year	$185	$43	$27	$255

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2006 *(in millions)*	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$1,295	$1,110	$(404)	$2,001
Investing activities				
Gross property additions	–	(865)	(707)	(1,572)
Nuclear fuel additions	–	(12)	(102)	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	1,242	415	1,657
Purchases of available-for-sale securities and other investments	(919)	(625)	(908)	(2,452)
Proceeds from sales of available-for-sale securities and other investments	898	724	1,009	2,631
Changes in advances to affiliates	409	(39)	(370)	–
Proceeds from repayment of long-term affiliate debt	131	–	(131)	–
Return of investment in consolidated subsidiaries	287	–	(287)	–
Other investing activities	(63)	(6)	46	(23)
Net cash provided (used) by investing activities	743	419	(1,035)	127
Financing activities				
Issuance of common stock	185	–	–	185
Dividends paid on common stock	(607)	–	–	(607)
Dividends paid to parent	–	(1,135)	1,135	–
Net decrease in short-term debt	–	(102)	(73)	(175)
Proceeds from issuance of long-term debt, net	397	–	–	397
Retirement of long-term debt	(2,091)	(109)	–	(2,200)
Retirement of long-term affiliate debt	–	(131)	131	–
Changes in advances from affiliates	–	(243)	243	–
Other financing activities	(8)	(8)	(52)	(68)
Net cash (used) provided by financing activities	(2,124)	(1,728)	1,384	(2,468)
Net decrease in cash and cash equivalents	(86)	(199)	(55)	(340)
Cash and cash equivalents at beginning of year	239	239	127	605
Cash and cash equivalents at end of year	$153	$40	$72	$265

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$257	$509	$701	$1,467
Investing activities				
Gross property additions	–	(714)	(599)	(1,313)
Nuclear fuel additions	–	(47)	(79)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	462	13	475
Purchases of available-for-sale securities and other investments	(1,702)	(405)	(1,878)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	1,702	405	1,738	3,845
Changes in advances to affiliates	333	5	(338)	–
Proceeds from repayment of long-term affiliate debt	369	–	(369)	–
Other investing activities	(12)	(26)	(2)	(40)
Net cash provided (used) by investing activities	690	(320)	(1,514)	(1,144)
Financing activities				
Issuance of common stock	208	–	–	208
Dividends paid on common stock	(582)	–	–	(582)
Dividends paid to parent	–	(2)	2	–
Net decrease in short-term debt	(170)	(191)	(148)	(509)
Proceeds from issuance of long-term debt, net	–	744	898	1,642
Retirement of long-term debt	(160)	(104)	(300)	(564)
Retirement of long-term affiliate debt	–	(369)	369	–
Changes in advances from affiliates	–	(101)	101	–
Other financing activities	(9)	50	(9)	32
Net cash (used) provided by financing activities	(713)	27	913	227
Net increase in cash and cash equivalents	234	216	100	550
Cash and cash equivalents at beginning of year	5	23	27	55
Cash and cash equivalents at end of year	$239	$239	$127	$605

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

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

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. The 2007 and 2006 amounts were restated for discontinued operations (See Note 3).

(in millions except per share data)	First[a]	Second[a]	Third[a]	Fourth[a]
2007				
Operating revenues	**$2,072**	**$2,129**	**$2,750**	**$2,202**
Operating income	**351**	**301**	**610**	**284**
Income from continuing operations	**159**	**106**	**327**	**101**
Net income (loss)	**275**	**(193)**	**319**	**103**
Common stock data				
Basic earnings per common share				
Income from continuing operations	**0.63**	**0.42**	**1.27**	**0.39**
Net income (loss)	**1.08**	**(0.75)**	**1.24**	**0.40**
Diluted earnings per common share				
Income from continuing operations	**0.62**	**0.41**	**1.27**	**0.39**
Net income (loss)	**1.08**	**(0.75)**	**1.24**	**0.40**
Dividends declared per common share	**0.610**	**0.610**	**0.610**	**0.615**
Market price per share – High	**51.60**	**52.75**	**49.48**	**50.25**
– Low	**47.05**	**45.15**	**43.12**	**44.75**
2006				
Operating revenues	$1,985	$2,083	$2,599	$2,057
Operating income	295	332	570	290
Income from continuing operations	67	110	268	106
Net income (loss)	45	(47)	319	254
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.27	0.44	1.07	0.42
Net income (loss)	0.18	(0.19)	1.27	1.01
Diluted earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.27	0.44	1.07	0.42
Net income (loss)	0.18	(0.19)	1.27	1.01
Dividends declared per common share	0.605	0.605	0.605	0.610
Market price per share – High	45.31	45.16	46.22	49.55
– Low	42.54	40.27	42.05	44.40

[a] Operating results have been restated for discontinued operations.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (UNAUDITED)

Years ended December 31 *(in millions, except per share data)*	2007	2006[a]	2005[a]	2004[a]	2003[a]
Operating results					
Operating revenues	**$9,153**	$8,724	$7,948	$7,168	$6,775
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	**693**	551	523	552	536
Net income	**504**	571	697	759	782
Per share data					
Basic earnings					
Income from continuing operations	**$2.71**	$2.20	$2.12	$2.28	$2.26
Net income	**1.97**	2.28	2.82	3.13	3.30
Diluted earnings					
Income from continuing operations	**2.70**	2.20	2.12	2.27	2.25
Net income	**1.96**	2.28	2.82	3.12	3.28
Assets	**$26,286**	$25,707	$27,066	$26,013	$26,198
Capitalization and Debt					
Common stock equity	**$8,422**	$8,286	$8,038	$7,633	$7,444
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93	93	93	93
Minority interest	**84**	10	36	29	24
Long-term debt, net[b]	**8,737**	8,835	10,446	9,521	9,693
Current portion of long-term debt	**877**	324	513	349	868
Short-term debt	**201**	–	175	684	4
Capital lease obligations	**247**	72	18	19	20
Total capitalization and debt	**$18,661**	$17,620	$19,319	$18,328	$18,146
Other financial data					
Return on average common stock equity (percent)	**5.97%**	7.05%	8.91%	9.99%	11.07%
Ratio of earnings to fixed charges	**2.62**	2.08	2.11	2.23	2.06
Number of common shareholders of record	**58,991**	64,899	67,638	70,159	72,792
Book value per common share	**$32.66**	$32.71	$32.35	$31.39	$30.94
Dividends declared per common share	**$2.45**	$2.43	$2.38	$2.32	$2.26
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	**51,163**	48,770	52,306	50,782	51,501
Nuclear	**30,336**	30,602	30,120	30,445	30,576
Combustion turbines/combined cycle	**13,319**	11,857	11,349	9,695	7,819
Hydro	**415**	594	749	802	955
Purchased	**14,994**	14,664	14,566	13,466	13,848
Total energy supply (Company share)	**110,227**	106,487	109,090	105,190	104,699
Joint-owner share[c]	**5,351**	5,224	5,388	5,395	5,213
Total system energy supply	**115,578**	111,711	114,478	110,585	109,912

[a] Operating results and balance sheet data have been restated for discontinued operations.
[b] Includes long-term debt to affiliated trust of $271 million at December 31, 2007 and 2006, and $270 million at December 31, 2005, 2004 and 2003 (See Note 23).
[c] Amounts represent co-owners' share of the energy supplied from the six generating facilities that are jointly owned.

We use ongoing earnings per share to evaluate the operations and to establish goals for management and employees. We believe this presentation is appropriate and enables investors to more accurately compare our ongoing financial performance over the periods presented. Ongoing earnings as presented here may not be comparable to similarly titled measures used by other companies. Reconciling adjustments from ongoing earnings per share to GAAP are as follows:

December 31	2007	2006	2005
Core ongoing earnings per share[a]	**$2.81**	$2.63	$2.70
Noncore ongoing earnings per share[b]	**(0.09)**	(0.19)	(0.19)
Total ongoing earnings per share	**2.72**	2.44	2.51
Contingent value obligations mark-to-market	**(0.01)**	(0.10)	0.03
Discontinued operations	**(0.74)**	0.08	0.70
Loss on debt redemptions	**-**	(0.14)	–
Postretirement and severance charges	**-**	-	(0.42)
Reported GAAP earnings per share	**$1.97**	$2.28	$2.82

[a] Core ongoing earnings primarily includes the utility operations, corporate eliminations and the holding company.
[b] Noncore ongoing earnings primarily includes the allocation of corporate overhead costs associated with divested business.

Contingent Value Obligation (CVO) Mark-to-Market

In connection with the acquisition of Florida Progress Corporation, we issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on after-tax cash flows above certain levels of four synthetic fuel facilities purchased by subsidiaries of Florida Progress Corporation in October 1999. The CVOs are debt instruments and, under GAAP, are valued at fair value. Unrealized gains and losses from changes in market value are recognized in earnings. Since changes in the fair value of the CVOs do not affect our underlying obligation, we do not consider the adjustment a component of ongoing earnings.

Discontinued Operations

The operations of businesses that have been sold or are in the process of being sold are reported as discontinued operations, and therefore we do not view these activities as representative of our ongoing operations. Our discontinued operations include CCO; Rowan and DeSoto; Winchester Energy; Progress Telecom, LLC; Dixie Fuels; Progress Materials, Inc.; Coal Mining; Progress Rail; MEMCO; Synthetic Fuels business; and Coal Terminal services.

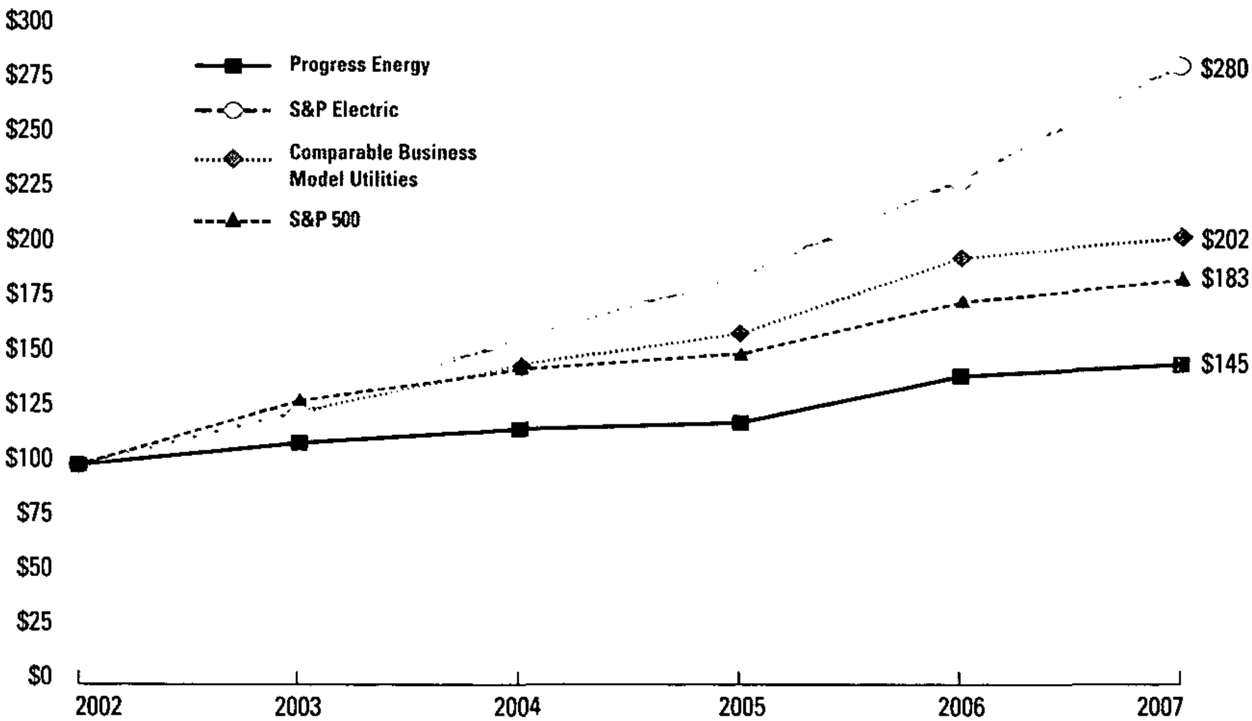
Loss on Redemptions of Debt

In November 2006, the Parent redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008. In December 2006, the Parent repurchased, pursuant to a tender offer, $550 million, or approximately 44.0 percent, of the aggregate principal amount of its 7.10% Senior Notes due March 1, 2011. Due to the nonrecurring nature of this loss, we do not believe it is representative of our ongoing operations.

Postretirement and Severance Charges

As part of our cost-management initiative, we approved a workforce restructuring in February 2005, which resulted in a reduction of approximately 450 positions. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program, in which 1,450 eligible employees elected to participate. In connection with this initiative, we incurred charges related to estimated future payments for severance benefits that will be paid out over time. Due to the nonrecurring nature of the charge, we do not believe it is representative of our ongoing operations.

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



Measurement Period (Fiscal Year Covered)	2002	2003	2004	2005	2006	2007
Progress Energy, Inc.	$100	$110	$116	$119	$140	$145
S&P 500 Index	100	129	143	150	173	183
Comparable Business Model Utilities	100	124	145	159	193	202
S&P Electric Index	100	124	157	185	228	280

[a] $100 invested on 12/31/2002 in Stock or Index. Including reinvestment of dividends. Fiscal year ending 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 have a market capitalization structure greater than $3.5 billion and are generally categorized in our subsector are Southern Company, Duke Energy, SCANA, Xcel, PG&E, Wisconsin Energy and Pinnacle West.

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 the industry evolution discussed above. 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 2008 annual meeting of shareholders will be held May 14, 2008, at 10 a.m. in the Fletcher Opera Theater at the Progress Energy Center for the Performing Arts in Raleigh, N.C. A formal notice of the meeting with a proxy statement will be mailed to shareholders in early April.

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.

We also offer online access to shareholder accounts via the Internet. To obtain online access to your shareholder account, go to computershare.com/investor to register.

If you have access to Progress Energy's annual report at your address, and do not want to receive a copy for your shareholder account, please call our transfer agent, Computershare, toll-free at **1.866.290.4388** to discontinue receiving annual reports by mail.

Dividend-reinvestment statements, tax documents and proxy material, including the annual report, can be electronically delivered to shareholders. Electronic delivery provides immediate access to proxy material and allows Internet voting while saving printing and mailing costs. To take advantage of electronic delivery of documents, go to **computershare.com/investor**, log in to your account, select Electronic Shareholder Communications and follow the instructions.

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

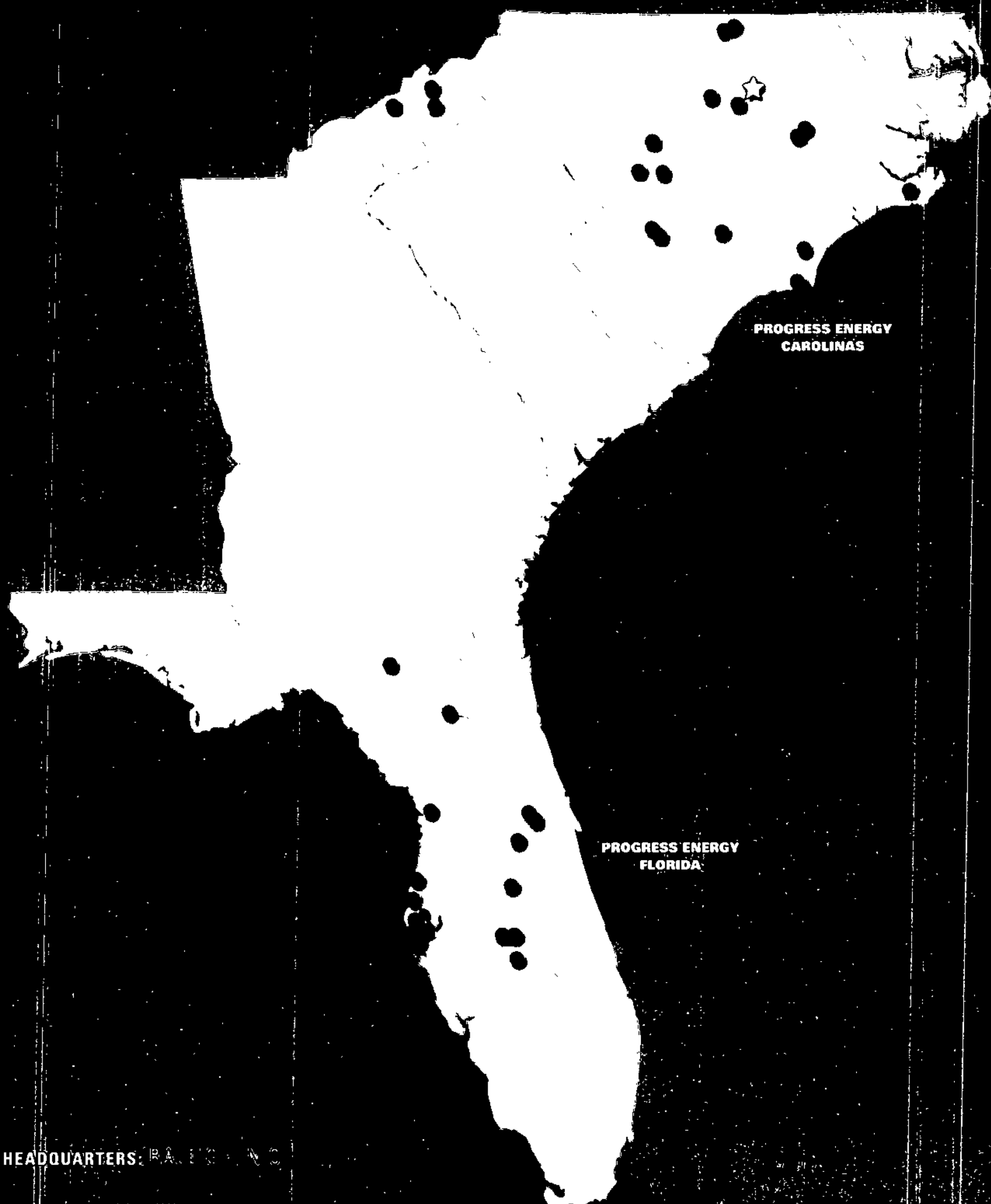
Progress Energy files periodic reports with the Securities and Exchange Commission that contain additional information about the company. Copies are available to shareholders upon written request to the company's treasurer at the corporate headquarters address.

This annual report is submitted for shareholders' information. 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.

NYSE Certifications

Because Progress Energy's common stock is listed on the NYSE, our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made his annual certification to that effect to the NYSE as of June 1, 2007. In addition, we have filed, as exhibits to the Annual Report on Form 10-K for the year ended December 31, 2007, the certifications of our principal executive officer and principal financial officer required under Section 302 of the Sarbanes-Oxley Act of 2002 to be filed with the Securities and Exchange Commission regarding the quality of our public disclosure.

PROGRESS ENERGY AT A GLANCE



HEADQUARTERS: RALEIGH, N.C.

EMPLOYEES: 10,500

CUSTOMERS: 3.1 MILLION

SERVICE TERRITORY: 54,000 SQUARE MILES

★ Progress Energy Corporate Headquarters

Generating Plant Locations

■ Progress Energy Regulated Service Areas

Environmental stewardship is Progress Energy's commitment, and my responsibility every day.

– Dave Bruzek, lead environmental specialist for natural resources, Progress Energy Florida

Progress Energy

Progress Energy, Inc.

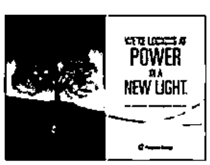
P.O. Box 1551

Raleigh, N.C. 27602-1551

progress-energy.com

Give us your feedback at progress-energy.com/annualreport.

To receive future copies electronically, visit computershare.com/investor.



See Progress Energy's Corporate Responsibility and Global Climate Change reports at progress-energy.com/environment.

END

FSC Mixed Sources

002CS-61033